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Battelle Columbus Labs., OH

Prepared for

Industrial Environmental Research Lab., Research Triangle Park, NC

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Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

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April 1979

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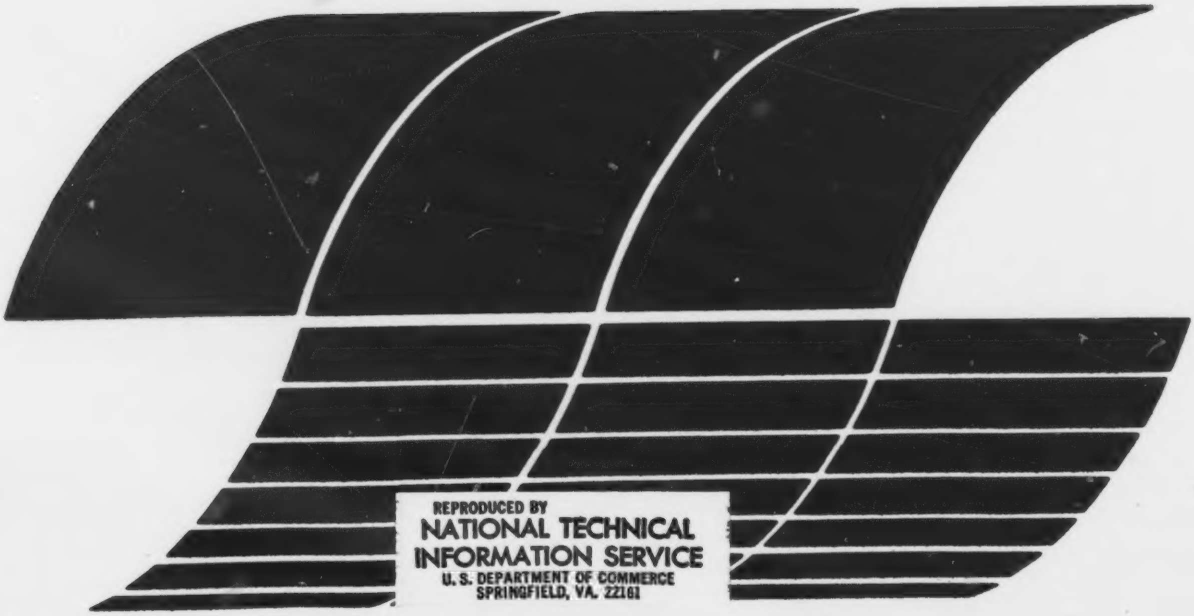
Interagency Energy/Environment R&D Program Report



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16. ABSTRACT

The proceedings document presentations made at the Symposium on Coal Cleaning to Achieve Energy and Environmental Goals, September 11-15, 1978, in Hollywood, Florida. The symposium provided an opportunity for mutual review and discussion of: the physical and chemical coal cleaning programs of EPA, DoE, the Electric Power Research Institute, and numerous industrial organizations; European and Soviet plans for the future; and problems of ongoing operations. The proceedings include the following topics: coal characteristics, coal cleaning overview, physical coal cleaning technology, environmental assessment and pollution control technology, and chemical coal cleaning technology. The first three topics are covered in Volume I; the last two, in Volume II.

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1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development
8. "Special" Reports
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This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

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EPA-600/7-79-098a

April 1979

Proceedings: Symposium on Coal Cleaning to Achieve Energy and Environmental Goals (September 1978, Hollywood, FL) -
Volume I

by

S.E. Rogers and A.W. Lemmon, Jr. (Editors)

Battelle Columbus Laboratories
505 King Avenue
Columbus, Ohio 43201

Contract No. 68-02-2163
Task No. 861
Program Element No. EHE624A

EPA Project Officer: James D. Kilgroe

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, NC 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

ABSTRACT

The Symposium on Coal Cleaning to Achieve Energy and Environmental Goals was sponsored by the U.S. EPA's Industrial Environmental Research Laboratory under Contract No. 68-02-2163, Task No. 861. The Symposium was held September 11-15, 1978, in Hollywood, Florida. The program provided an opportunity for mutual review and discussion of the physical and chemical coal cleaning programs of EPA, DoE, the Electric Power Research Institute, those of numerous industrial organizations, and European and Soviet plans for the future, as well as the problems of ongoing operations.

The Proceedings contain the contributions of the participating speakers and include the following topics:

(a) Coal Characteristics
(b) Coal Cleaning Overview
(c) Physical Coal Cleaning Technology
(d) Environmental Assessment and Pollution Control Technology
(e) Chemical Coal Cleaning Technology.

FOREWORD

Man and his environment must be protected from the adverse effects of pesticides, radiation, noise, industrial effluents, and other forms of pollution, as well as the unwise management of solid waste. Efforts to protect the environment require a focus that recognizes the interplay among the components of our physical and biological environment--air, water, land, plants, and animals. The Industrial Environmental Research Laboratory (IERL/RTP) of the U.S. Environmental Protection Agency (EPA) located at Research Triangle Park, North Carolina, contributes to this multidisciplinary focus through programs engaged in:

- studies on the effects of environmental contaminants on the biosphere, and
- a search for ways to prevent contamination and to recycle valuable resources.

This Symposium Proceedings deals with the subject matter of concern to an IERL/RTP program designed to focus on the effectiveness and efficiency of coal cleaning processes as a means of reducing the total environmental impact of energy production through coal utilization. The Symposium itself provided a most vital communication link between the researcher and engineer on the one hand and the user community on the other. To enhance future communication processes and encourage future applications of coal cleaning technology, this Symposium Proceedings documents the results of the meeting held.

ACKNOWLEDGMENT

No symposium can be a success without the support and participation of the attendees. For those participants listed elsewhere in this document, then, we are grateful for their contributions. Thanks in full measure is due also to the Session Chairmen and Cochairmen who patiently labored to formulate an informative and timely program. And, of course, none of this would have been possible without the long hours spent by the authors individually and collectively, in the preparation of their papers.

Thanks are also due for the handling of the mechanical details of the Symposium. These necessary functions were performed ably by a number of people. Mr. Jack H. Greene (IERL/RTP) was responsible for the overall arrangements with the hotel, and Ms. Susan R. Armstrong, Conference Coordinator at Battelle's Columbus Laboratories (BCL), managed the day-to-day activities. She was assisted in the many details of the necessary operations by Ms. Joyce B. Fowler (IERL/RTP), Mrs. Rebecca S. Miller (BCL), and Mrs. Lucy G. Pierson (BCL).

Special thanks are expressed to Mrs. Alexis W. Lemmon, Jr., and Mrs. L. David Tamny for their efforts in making the week more pleasant for the distaff accompaniers of the Symposium participants.

In the preparation of the printed Symposium Proceedings, Ms. Sharron E. Rogers performed excellently as Technical Editor. Mrs. Miller and Mrs. Pierson organized, formatted, and provided the necessary typing. We are grateful for their assistance.

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[2]Exxon Production Research Company

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EPA

Symposium on Coal Cleaning to Achieve Energy and Environmental Goals

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FINAL PROGRAM

EPA Symposium on Coal Cleaning to Achieve Energy and Environmental Goals

Symposium Chairman
James D. Kilgroe
U.S. EPA, IERL-RTP

Symposium Cochairman
Alexis W. Lemmon, Jr.
Battelle's Columbus Laboratories

Monday, September 11, 1978

1:00—Registration—Mezzanine Lounge

Session 0: Coal Characteristics

2-5 p.m.—Regency West

Chairman: David A. Kirchgessner
U.S. EPA
Industrial Environmental Research Laboratory (IERL-RTP)

Cochairman: Harold L. Lovell
Pennsylvania State University

2:00 **Petrography of Coal**
Ron W. Stanton
U.S. Geological Survey

2:20 **Mineralogic Affinities of Trace Elements in Coal**
Faith Fiene
Illinois State Geological Survey

2:50 **Effects of Coal Cleaning on Elemental Distributions**
Charles T. Ford and James F. Boyer, Jr
Bituminous Coal Research

3:20 *Coffee Break*

3:30 **Particle Size Distribution in Liberation of Pyrite**
Harold L. Lovell
Pennsylvania State University

4:00 **Contaminants in Coal: Geology and Size—Gravity Separations**
C. Blaine Cecil
U.S. Geological Survey

4:30 **Interpreting Statistical Variability**
Ralph E. Thomas
Battelle's Columbus Laboratories

7-9 p.m. **Welcome Reception—Regency North**

Tuesday, September 12, 1978

8:00 a.m.—Registration—Mezzanine Lounge

Session 1: Coal Cleaning Overview

Morning Program—9 a.m.-12 Noon

Chairman: James D. Kilgroe
U.S. EPA, IERL-RTP

9:00 **Welcome**
Norbert Jaworski, Deputy Director
U.S. EPA, IERL-RTP

9:15 **Introductory Remarks**
James D. Kilgroe, Symposium Chairman
U.S. EPA, IERL-RTP

9:30 **Overview of EPA Coal Cleaning Programs**
David A. Kirchgessner and James D. Kilgroe
U.S. EPA, IERL-RTP

10:00 **Overview of DOE Coal Cleaning Programs**
Cyril W. Draffin
Department of Energy (DOE)

10:30 *Coffee Break*

10:45 **Overview of EPRI Coal Cleaning Programs**
Kenneth Clifford and Shelton Ehrlich
Electric Power Research Institute

11:15 **An Integrated Assessment of Coal Technologies**
Roger Hansen
U.S. EPA, IERL-RTP
Richard Davidson
Battelle's Columbus Laboratories

12:00 Noon Luncheon—Les Ambassadeurs Room
Impacts of the 1977 Clean Air Act Amendment
Luncheon Speaker: Frank Princiotta
Office of Energy, Minerals and Industry
U.S. Environmental Protection Agency

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Afternoon Program — 2-5 p.m.

Chairman: Kenneth Clifford
Electric Power Research Institute

2:00 **Environmental Protection Against the Influence of Coal-Preparation Plants in the USSR**
I. S. Blagov, G. G. Vosnyuk, V. V. Kochetov,
I. Ch. Nekhoroshy, and I. E. Cherevko
USSR, Ministry of Coal

2:30 **Clean Fuel Supply Requirements for the OECD Countries**
Gary J. Foley
Organization of Economic Cooperation and Development
Richard Livingston
U.S. Environmental Protection Agency

3:00 **A Technical and Economic Overview of Coal Cleaning**
Horst Huettenhain, Bechtel Corporation
Samuel Wong, Argonne National Laboratory

3:30 *Coffee Break*

3:45 **An Evaluation of Institutional, Economic, Regulatory and Legislative Barriers to Investment in Physical Coal Cleaning as an SO_2 Emission Control Strategy**
Karel Fisher and Peter M. Cukor
Teknekron, Inc.

4:15 **Economics of Coal Cleaning and Flue Gas Desulfurization for Compliance with Revised NSPS for Utility Boiler**
R. M. Cole
Tennessee Valley Authority

4:45 **Impact of Transportation and Beneficiation on the Utilization of High Sulfur Coal**
C. Phillip Baumel, Thomas P. Drinka and John J. Miller
Ames Laboratory, Iowa State University

Wednesday, September 13, 1978

Session 2: Physical Coal Cleaning Technology

Morning Program — 9 a.m.-12 Noon

Chairman: Richard E. Hucko
Coal Preparation and Analysis Laboratory
U.S. Department of Energy

9:00 **An Evaluation of the Desulfurization Potential of U.S. Coals**
Jane H. McCreery and Fredrick K. Goodman
Battelle's Columbus Laboratories

9:30 **The Use of Coal Cleaning for Complying with SO_2 Emission Regulations**
Elton Hall, Battelle's Columbus Laboratories
Gilbert E. Raines, Resource Dynamics, Inc.

10:00 **Statistical Correlations on Coal Desulfurization by Crushing and Specific Gravity Separation**
Ralph E. Thomas
Battelle's Columbus Laboratories

10:30 *Coffee Break*

10:45 **Dewatering and Drying of Fine Coal: Performance and Costs**
Donald Sargent and William Cheng
Versar Inc.

11:15 **Homer City Coal Cleaning Demonstration, Test, and Technology Evaluation Program**
James H. Tice
Pennsylvania Electric Company

11:45 **Computer Control of Coal Preparation**
Gerry Norton, Clive Longden, and George Hambleton
Norton, Hambleton Associates

Afternoon Program — 2-5 p.m.

Chairman: Kenneth Harrison
Heyl & Patterson, Inc.

2:00 **Physical and Physicochemical Removal of Sulfur from Coal**
Ray W. Fisher and David Birlingmair
Ames Laboratory
Iowa State University

2:30 **Cleaning of Eastern Bituminous Coals by Fine Grinding, Froth Flotation and High Gradient Magnetic Separation**
W. L. Freyberger, J. W. Keck, D. W. Spottiswood,
N. D. Solem and Virginia L. Doane
Michigan Technological University

3:00 **The Potential of Magnetic Separation in Coal Preparation**
Frederick V. Karlson, Horst Huettenhain, William W. Slaughter
Bechtel National Inc.
Kenneth L. Clifford
EPRI

3:30 *Coffee Break*

3:45 **Testing of Commercial Coal Preparation Plants with a Mobile Laboratory**
William Higgins and Thomas Plouf
Joy Manufacturing Co.

4:15 **Chemical Comminution—an Improved Route to Clean Coal**
V. C. Quackenbush, R. R. Maddocks, and G. W. Higginson
Catalytic, Inc.

4:45 **Coal Cleaning by the Otisca Process**
Speaker to be announced

6-9 p.m. **Social Hour and Banquet — Les Ambassadeurs Room**
Tomorrow's Energy Supplies
Banquet Speaker: Richard J. Anderson
Formerly Associate Director, Battelle's
Energy Program; Currently Consultant to
Battelle Memorial Institute

Thursday, September 14, 1978

Session 3: Environmental Assessment and Pollution Control Technology

Morning Program—9 a.m.-12 Noon

Chairman: G. Ray Smithson, Jr.
Battelle's Columbus Laboratories

9:00 **Introduction to the EPA Program**
T. K. Janes
EPA, IERL-RTP

9:20 **Environmental Assessment Methodologies for Fossil Energy Processes**
R. P. Hangebrauck
EPA, IERL-RTP
J. L. Warren
Research Triangle Institute

9:50 **Review of Regulations and Standards Influencing Coal Cleaning**
Peter Van Voris
Battelle's Columbus Laboratories
J. W. Harrison
Research Triangle Institute

10:20 *Coffee Break*

10:30 **Environmental Impact Assessment of Coal Cleaning Processes**

- Establishing Goals
  Barney W. Cornaby
  Battelle's Columbus Laboratories
- Overall Methodology
  Robert A. Ewing
  Battelle's Columbus Laboratories
- Biological Transport
  Peter Van Voris
  Battelle's Columbus Laboratories
- Physical Transport and Partition Functions
  Gilbert E. Raines
  Raines Consulting, Inc.

11:30 **Methodology Application to Homer City Background Data: Comparison with MEG Values**
D. A. Tolle
Battelle's Columbus Laboratories

12:00 Noon Luncheon—Les Ambassadeurs Room
Luncheon Host: Edward W. Ungar, Director
Battelle's Columbus Laboratories

Afternoon Program—2 p.m.-5 p.m.

Chairman: C. Grua
U.S. Department of Energy

2:00 **An Overview of Control Technology**
Alexis W. Lemmon, Jr., Gerald L. Robinson, and David Sharp
Battelle's Columbus Laboratories

2:30 **Effluents from Coal Preparation**
K. Randolph
Versar, Inc.

3:00 **Control of Trace Element Leaching from Coal Preparation Wastes**
E. M. Wewerka
Los Alamos Scientific Laboratory

3:20 *Coffee Break*

3:30 **Stabilization of Coal Preparation Plant Sludges**
David Hoffman
Dravo Lime Company

4:00 **Chemical and Biological Characterization of Leachate from Coal Cleaning Wastes**
R. A. Griffin, et al.
Illinois State Geological Survey

Friday, September 15, 1978

Session 4: Chemical Coal Cleaning

Morning Program — 9 a.m.-12 Noon

Chairman: Thomas D. Wheelock
Iowa State University

9:00 **Introduction to Chemical Cleaning**
R. A. Meyers
TRW Inc.

9:20 **Current Status of Chemical Coal Cleaning Processes—An Overview**
Lee C. McCandless and G. Y. Contos
Versar, Inc.

9:50 **Status of the Reactor Test Project for Chemical Removal of Pyritic Sulfur from Coal**
L. J. Van Nice and M. J. Santy
TRW Inc.
E. Bobalek and L. D. Tamny
U.S. EPA, IERL-RTP

10:20 *Coffee Break*

10:30 **Status of Hydrothermal Processing for Chemical Desulfurization of Coal**
E. P. Stambaugh, J. F. Miller, H. N. Conkle, B. C. Kim, and E. J. Mezey
Battelle's Columbus Laboratories

11:00 **Survey of Coals Treated by Oxydesulfurization**
R. P. Warzinski, S. Friedman, and F. W. Steffgen
Pittsburgh Energy Research Center—DOE

11:30 **Coal Desulfurization by Leaching with Alkaline Solution Containing Oxygen**
Richard Markuszewski, K. C. Chuang, and Thomas D. Wheelock
Ames Laboratory, Iowa State University

Afternoon Program — 2-5 p.m.

Chairman: Robin R. Oder
Gulf Research and Development Co.

2:00 **Potential for Chemical Coal Cleaning: Reserves, Technology, and Economics**
R. A. Giberti, R. S. Opalanko, and Joachim R. Sinek
Kennecott Copper Corp.

2:20 **JPL Coal Desulfurization Process by Low Temperature Chlorinolysis**
John J. Kalvinskas and George Hsu
Jet Propulsion Laboratory

2:40 **Oxidative Coal Desulfurization Using Nitrogen Oxides—the KVB Process**
E. D. Guth
KVB, Inc.

3:00 *Coffee Break*

3:20 **The Dry Removal of Pyrite and Ash from Coal by the Magnex Process—Process Variables and Clean Coal Properties**
James K. Kindig and Duane N. Goens
Hazen Research, Inc.

3:40 **Panel Discussion on Prospects for Characterization and Removal of Organic Sulfur from Coal**
Chairman: Robin R. Oder
Gulf Research and Development Co.

Panelists: Sidney Friedman
Pittsburgh Energy Research Center—DOE

Amir Attar
University of Houston

Douglas M. Jewell
Gulf Research and Development Co.

Thomas G. Squires
Iowa State University

CONFERENCE REPORT AND ACTIVITIES

The Symposium on Coal Cleaning to Achieve Energy and Environmental Goals provided a major forum for technical interchange among engineers and scientists concerned with the development and use of coal cleaning technology. The conference, sponsored by the U.S. Environmental Protection Agency's Industrial Environmental Research Laboratory of Research Triangle Park, North Carolina, was held in Hollywood, Florida, on September 11-15, 1978.

Approximately 225 engineers, environmental scientists, geologists, and managers from the coal industry, R&D organizations, coal users, planning agencies, and government attended the five-day conference at which papers were given on coal characteristics, coal cleaning overview, physical coal cleaning technology, environmental assessment and pollution control technology, and chemical coal cleaning.

Mr. Frank Princiotta, Director of the Energy Processes Division, Office of Energy Minerals and Industry, U.S. EPA, addressed the first Symposium luncheon on the "Impacts of the 1977 Clean Air Act Amendment". The audience showed particular interest in his review of the status and substance of the draft New Source Performance Standards, which were published that week.

The Symposium banquet was highlighted by the presentation, "Tomorrow's Energy Supplies", by Mr. Richard J. Anderson, Consultant to Battelle Memorial Institute, and a brief address by Mr. Gennadiy G. Voznyuk, Chief of Nature Protection, Directorate, U.S.S.R. Ministry of Coal Industry of the Soviet Union. The Soviet representatives to the conference were honored and seated at the head table at the banquet. They included Mr. Viktor Kochetov, General Director, Donetskugleobogashcheniye, U.S.S.R. Ministry of Coal Industry; Mr. Ivan Nekhoroshiy, Chief of Laboratory of IOTT, U.S.S.R. Ministry of Coal Industry; and Mr. Voznyuk. Simultaneous translation was provided during all technical sessions as well as social functions of the Symposium.

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A second Symposium luncheon was hosted by Dr. Edward Ungar, Director of Battelle's Columbus Laboratories (BCL), at which conference organizers, Mr. James Kilgroe of EPA-RTP and Mr. Alexis W. Lemmon, Jr., of BCL, were recognized.

Some technical highlights of the Symposium included the paper presented by Mr. Nekhoroshiy of the Soviet delegation and several first time reports from major ongoing coal cleaning research programs. "Primary Trends of Works on Environmental Protection Against the Influence of Coal-Preparation Plants in the U.S.S.R.", the subject of Mr. Nekhoroshiy's presentation, drew much audience interest. K. Randolph of Versar, Inc., reported in his paper on "Effluents from Coal Preparation" that proof has been obtained for the existence of priority pollutants in effluents from coal cleaning. J. McCreery of Battelle reported that the amount of low-sulfur coals which can be made available in the United States to meet the 1.2 lb $SO_2/10^6$ Btu NSPS is approximately 41 percent of total reserves as opposed to an earlier figure reported in the literature of 14 percent. Her presentation was "An Evaluation of the Desulfurization Potential of U.S. Coals".

The entire program on Thursday, September 14, provided a detailed overview of the plans and progress of the environmental assessment of coal cleaning. The methodological approaches shared will be of use to many current and future coal cleaning developments. Perhaps the most useful result of the program was the mutual opportunity to review and discuss the physical and chemical coal cleaning programs of EPA, DoE, Electric Power Research Institute, those of numerous industrial organizations, and European and Soviet plans for the future, as well as the problems of ongoing operations.

PETROGRAPHY OF COAL

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ABSTRACT

Coal is a sedimentary rock composed of microscopically recognizable organic constituents (macerals) and inorganic constituents (minerals). By American Society for Testing and Materials (ASTM) definition, pure coal contains less than 25 percent ash by weight, and impure coal contains 25-50 percent ash.

Macerals are products of coalified remains of plants; they have been divided into groups: vitrinite, exinite, and inertinite. Vitrinite macerals represent partially decomposed woody-plant tissues. If cell structure is retained, the variety of vitrinite is termed telinite; if cell structure is not visible, the variety is termed collinite. The reflectance of vitrinite may be used as a measure of the degree of metamorphism of the coal. Exinite macerals are remnant parts of plants such as spores (sporinite), cuticles (cutinite), resins (resinite), and algae (alginite); they differ chemically and morphologically from vitrinite. Inertinite macerals result from the oxidation or alteration of other macerals and include semifusinite, fusinite, micrinite, macrinite, and sclerotinite.

Major minerals in coal include quartz, marcasite, pyrite, siderite, calcite, and dolomite. The more common accessory minerals in coal are rutile (TiO_2), sphalerite (ZnS), chalcopyrite ($CuFeS_2$), zircon ($ZrSiO_4$), and monazite ($((Ce,LA)PO_4)$). These minerals are either allogenic (minerals transported into peat-forming environments) or authigenic (minerals that formed in the peat).

Maceral analysis and vitrinite reflectance can be used to predict coking, gasification, and liquefaction potentials of coals and also can be used to determine certain geologic conditions prevailing during peat accumulation and coalification.

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6.-- Alginite (A) in (a) incident light and (b) incident light, blue irradiation.

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INTRODUCTION

For some thousands of years, coal has been extracted from the earth and burned. In most applications, upon combustion, this homogeneous-appearing substance yields heat, smoke, and ash. Because of the increased awareness of environmental quality, the need has arisen for a coal product that behaves as a clean fuel and is economically acceptable.

Effective coal cleaning (physical or chemical) depends on the basic properties of coal, which is not a homogeneous substance but a complex mixture of microscopic components, each having different chemical and physical properties.

COMPOSITION OF COAL

Coal, in the geologic sense, is a sedimentary rock that is combustible. By convention, coal is distinguished from shale by its ash content, which is the residual product of coal upon combustion (fig. 1).

Coal is similar to other rocks (fig. 2) in that it contains minerals; however, it differs because it is predominantly composed of macerals (organic matter). Macerals have textural characteristics inherited from the original plant material, have variable chemical compositions, are noncrystalline, and have distinct reflectance in polished sections (Stach and others, 1975). Minerals, on the other hand, have defined chemical compositions and crystallographic properties.

Macerals are sensitive to minor increases in metamorphism. The measured reflectance of certain macerals indicates the degree of coal metamorphism from lignite through anthracite (Stach, and others 1975). The molecular structure of macerals is generally aliphatic but when metamorphism (coalification) increases this structure gradually takes on a more aromatic character (Stach and others, 1975). Some minerals, for example the clays, may be also affected by changes in metamorphism.

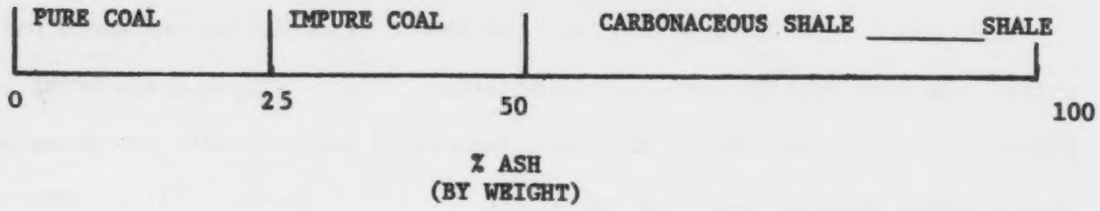
PURE COAL
IMPURE COAL
CARBONACEOUS SHALE
SHALE
0
25
50
100
% ASH
(BY WEIGHT)

Figure 1. -- ASTM definition of coal on the basis of ash content (Am. Soc. Testing Materials, 1977).

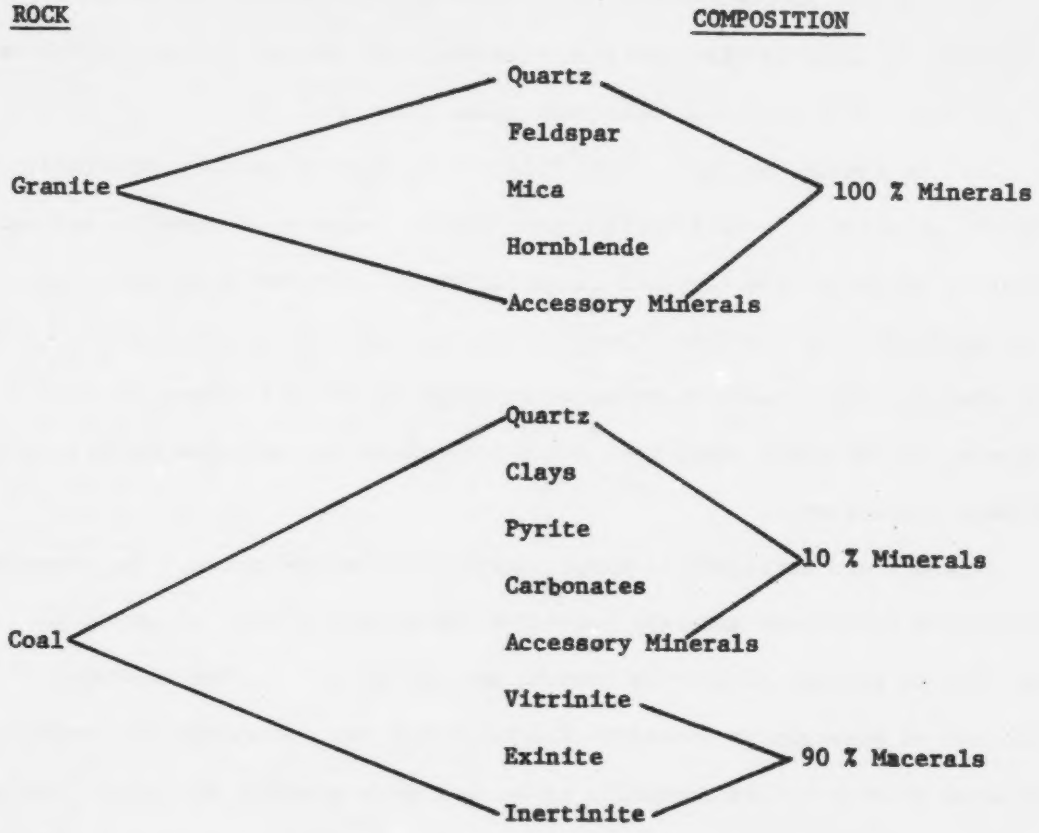
ROCK
COMPOSITION
Granite
Quartz
Feldspar
Mica
Hornblende
Accessory Minerals
100 % Minerals
Coal
Quartz
Clays
Pyrite
Carbonates
Accessory Minerals
10 % Minerals
Vitrinite
Exinite
Inertinite
90 % Macerals

Figure 2.-- Comparison of the composition between granite and coal.

MACERALS

The major groups of macerals are vitrinite, exinite, and inertinite, each of which can be subdivided (Internat. Comm. Coal Petrology, 1963, 1971; Stach and others, 1975). Table 1 lists the microscopic characteristics, probable maceral origin and chemical composition, the approximate density, and the relative abundance of each maceral group in most bituminous coals.

Figures 3 - 8 are photomicrographs of various macerals as seen in incident and transmitted light (50X oil immersion). Depending on sample preparation, combinations of transmitted light, incident light, and incident light,blue-excitation can be used to identify macerals.

Woody tissues, leaves, spores, and algal mats are among the probable sources of material that, through alteration and subsequent compaction, produce macerals. Figure 9 schematically illustrates the source of the precursors of macerals and where they may originate in a given swamp.

MINERALS

Minerals occur in coal in a wide variety of forms, including concretions, fracture and cleat fillings, partings, and lenses; other minerals are finely disseminated in the macerals (Mackowsky, 1968). All these minerals plus inorganic elements that are organically bound in coal have been referred to as "mineral matter" (Rao and Gluskoter, 1973). Although the normative mineralogy can be inferred from bulk chemical analysis of coal, the actual minerals must be identified microscopically and their identification confirmed by X-ray diffraction. The major minerals found in most coals are as follows:

QUARTZ	SiO_2	ILLITE	$KAl_2(Si_3Al)O_{10}(OH)_2$
CALCITE	$CaCO_3$	KAOLINITE	$Si_2Al_2O_5(OH)_4$
SIDERITE	$FeCO_3$	MONTMORILLONITE	Ca-Fe-Mg-Al - silicate
ANKERITE	$CaMgFe(CO_3)_4$	PYRITE	FeS_2
DOLOMITE	$CaMg(CO_3)_4$	MARCASITE	FeS_2

MACERAL GROUP	MICROSCOPIC CHARACTERISTICS OF MACERAL VARIETIES	ORIGIN	GENERAL COMPOSITION	APPROXIMATE DENSITY (30% volatile)	APPROXIMATE RELATIVE ABUNDANCE (volume %)
VITRINITE	-GREY IN REFLECTED LIGHT; RED IN TRANSMITTED LIGHT - - COLLINITE - NO VISIBLE CELL STRUCTURE - TELINITE - VISIBLE CELL STRUCTURE - VITRODETRINITE - SMALL FRAGMENTS OF VITRINITE	HUMIC ACID FRACTION OF HUMIC SUBSTANCES DERIVED THROUGH MOULDERING AND PEATIFICATION OF PLANT CELL WALLS COMPOSED OF LIGNIN AND CELLULOSE	HUMINS WITH AROMATIC NUCLEUS SURROUNDED BY PERIPHERAL ALIPHATIC GROUPS	1.2 G/CM^3	70
EXINITE	--DARK GREY IN REFLECTED LIGHT; YELLOW IN TRANSMITTED LIGHT; YELLOW TO ORANGE IN BLUE OR ULTRAVIOLET LIGHT (FLUORESCENCE) - SPORINITE -OULTINE OF COMPACTED SPORE - CUTINITE - OUTLINE OF COMPACTED CUTICLE - RESINITE - DARK CELL AND VOID FILLINGS - ALGINITE - DARK GLOBULAR MASSES - LIPTODETRINITE - SMALL FRAGMENTS OF EXINITE	HYDROGEN - RICH PLANT PARTS SUCH AS SPORINE, CUTINE, RESINS, WAXES FATS AND OILS OF VEGETABLE MATTER MOST VARITIES ARE VERY RESISTANT TO COALIFICATION	SPORINITE-- ALIPHATIC-AROMATIC SKELETON WITHOUT FATTY ACID ANHYDRIDES, SOME STEROID ZONES CUTINE--GLYCERINE ESTERS OF FATTY ACIDS. RESINS -- HIGHER IN HYDROGEN CONTENT	1.1 G/CM^3	0 - 7
INERTINITE	-WHITISH GREY TO WHITE IN REFLECTED LIGHT; OPAQUE IN TRANSMITTED LIGHT - FUSINITE - HIGHLY REFLECTING; CELL STRUCTURE DISTINCT - SEMIFUSINITE- REFLECTANCE BETWEEN VITRINITE AND FUSINITE; SOME CELL STRUCTURE - MACRINITE - NO CELL STRUCTURE; REFLECTANCE HIGHER THAN VITRINITE - MICRINITE - SMALL GRANULAR GROUNDMASS; HIGHLY REFLECTING - SCLEROTINITE - ROUND BODIES WITH CAVITIES; HIGHLY REFLECTING - INERTODETRINITE - SMALL FRAGMENTS OF INERTINITE	OXIDATION OF VARIOUS PLANT PARTS PRIMARILY CELL WALLS; SCLEROTINITE MAY ORIGINATE FROM FUNGAL REMAINS.	HIGH CARBON AND LOW HYDROGEN CONTENTS; GREATER DEGREE OF AROMATIZATION AND CONDENSATION	1.4 - 1.5 G/CM^3	10 -20

Table 1.-- General characteristics of bituminous coal macerals (information from Stach and others, 1975; Internat. Comm. Coal Petrology.

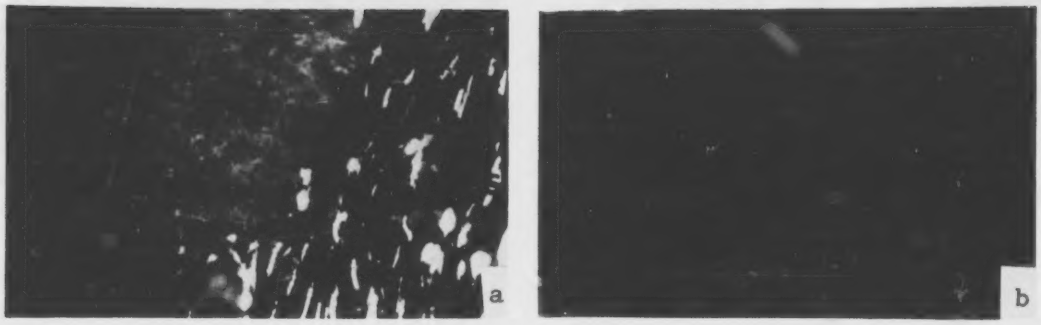

Figure 3. -- Photomicrographs of vitrinite in (a) transmitted light and (b) incident light. V, vitrinite; S, sporinite.

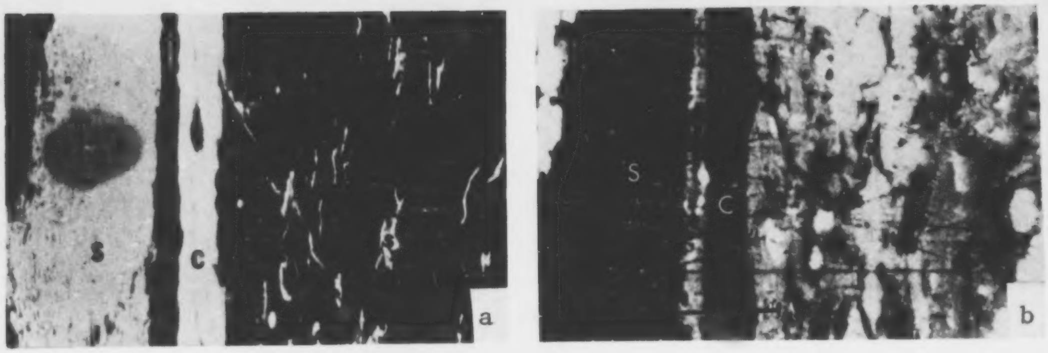

Figure 4. -- Photomicrographs of exinite in (a) transmitted light and (b) incident light. C, cutinite; S, sporinite.

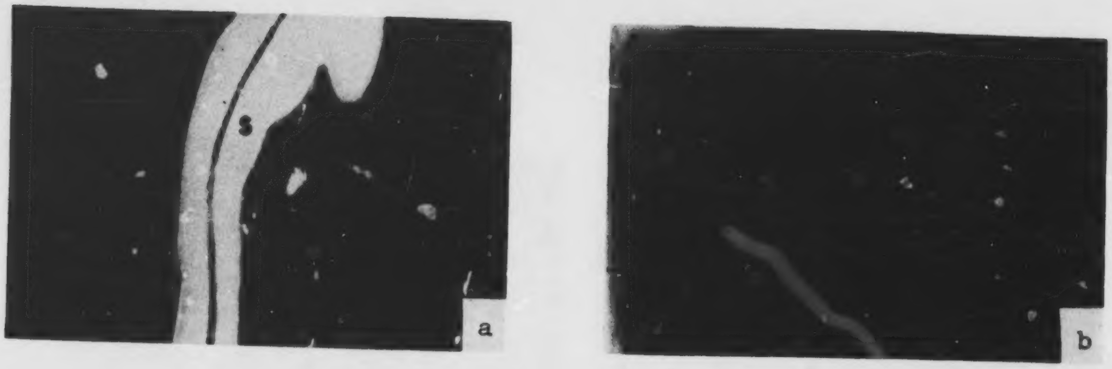

Figure 5. - Photomicrographs of sporinite (macrospore) in (a) transmitted light and (b) incident light. S, sporinite; V, vitrinite.

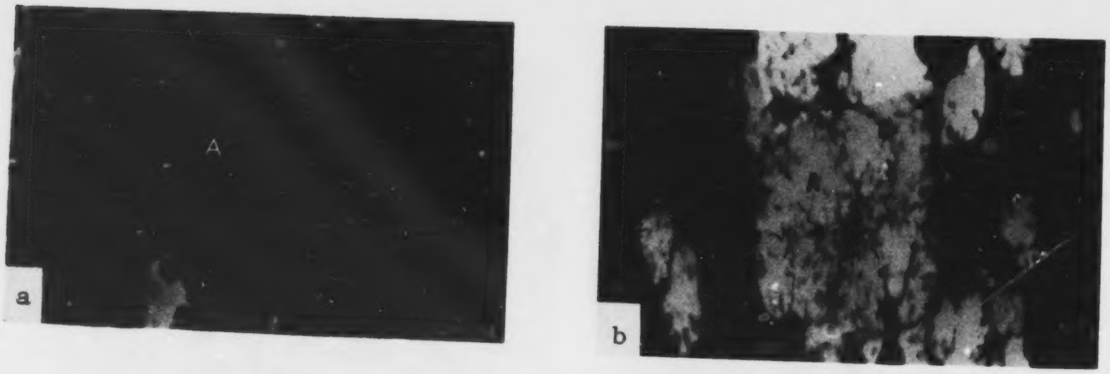

Figure 6. - Photomicrographs of alginite (A) in (a) incident light and (b) incident light, blue irradiation.

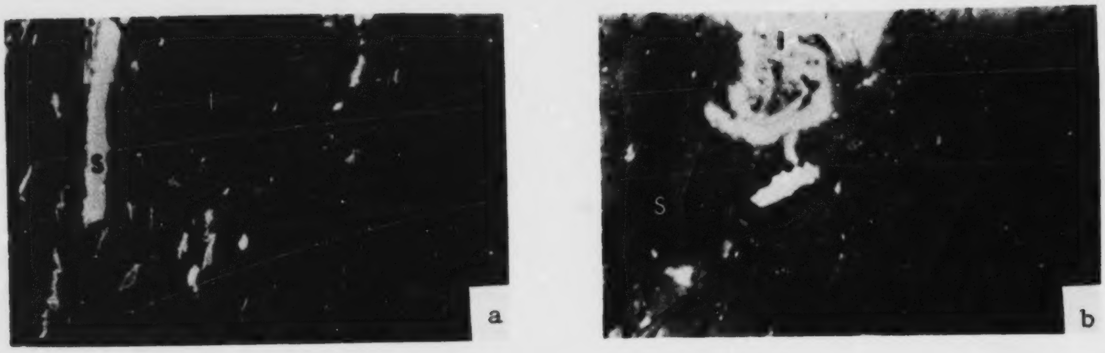

Figure 7. - Photomicrographs of inertinites in (a) transmitted light and (b) incident light. I, inertinite; S, sporinite; v, vitrinite.

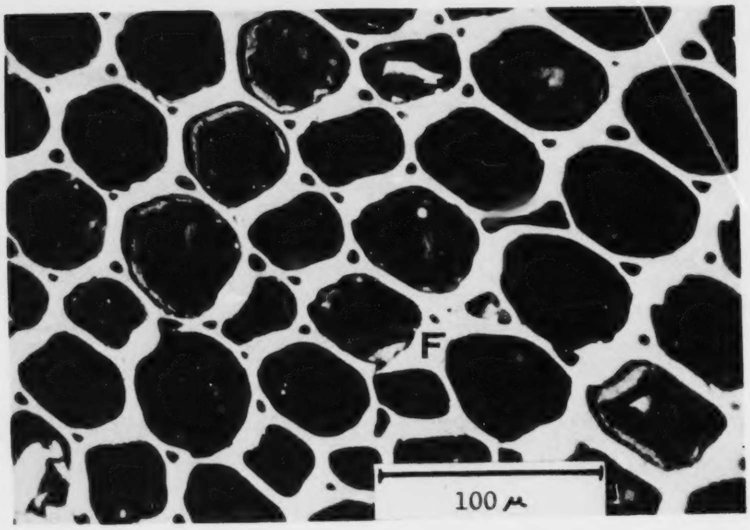

Figure 8. - Photomicrograph of fusinite (F) in incident light showing open cell structure.

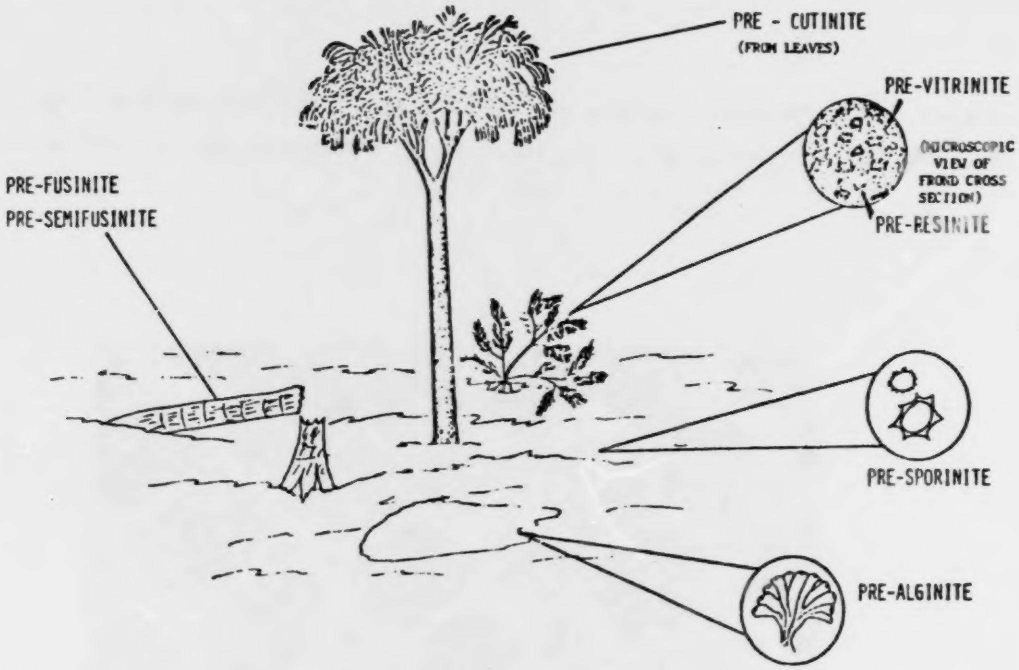
PRE - CUTINITE
(FROM LEAVES)
PRE-VITRINITE
(MICROSCOPIC VIEW OF FROND CROSS SECTION)
PRE-RESINITE
PRE-FUSINITE
PRE-SEMIFUSINITE
PRE-SPORINITE
PRE-ALGINITE

Figure 9.--Parts of Peat-forming plants that form macerals

Both the relative and absolute abundances of these major minerals differ widely within and among coal beds. Examples of major minerals in polished blocks of coal are shown in figures 10-12. The quartz shown in figure 12 is a common form of the mineral in many coals, whereas the morphology, maceral association, and particle size of pyrite can differ both vertically and laterally within any given coal bed (fig. 10 and 11). Of the above-listed minerals,clay, quartz, and pyrite are common in coal. In addition to the above minerals, appreciable concentrations of the iron oxide and sulfate minerals may be present in weathered (oxidized) coal; sulfate minerals may also occur in low-rank coal such as lignite but are rare in fresh, higher rank coal.

About 100 accessory minerals some of which may control the distribution of many trace elements (Finkelman, 1978) have been found in coal. Recent studies strongly indicate that much of the Se, Pb, Cu, Zn, and Cd in Appalachian coal may be in the accessory minerals (Finkelman and others, 1979). The following is a list of the common accessory minerals.

APATITE	$Ca_5(PO_4)_3(OH)$	HYPERSTHENE	$(Mg,Fe)_2SiO_6$
BARITE	$BaSO_4$	ILMENITE	$FeTiO_3$
BIOTITE	K-Mg-Fe-Al silicate	MAGNETITE	Fe_3O_4
CHALCOPYRITE	$CuFeS_2$	MONAZITE	$CePO_4$
CHLORITE	Fe-Al silicate	MUSCOVITE	$KAl_2(AlSi_3)O_{10}(OH)_2$
CLAUSTHALITE	PbSe	PLAGIOCLASE	$(Na,Ca)(Al,Si)_4O_8$
CRANDALLITE	$(Ca,Ba,Sr)Al_3(PO_4)_2(OH)_5 \cdot H_2O$	RUTILE	TiO_2
DIASPORE	AlO(oH)	SPHALERITE	ZnS
GALENA	PbS	SPHENE	$CaTiO_5$
GOETHITE	$Fe_2O_3 \cdot H_2O$	SYLVITE	KCl
GOLD	Au	TALC	$Mg_3Si_4O_{10}(OH)_2$
GYPSUM	$CaSO_4H_2O$	TOURMALINE	complex boro-silicates
HALITE	NaCl	XENOTIME	YPO_4
HEMATITE	Fe_2O_3	ZIRCON	$ZrSiO_4$

The study of minerals in coal was long hampered by the difficulty in removing extremely fine-grained minerals from the organic constituents until Gluskoter (1965) used an electronic low-temperature asher to oxidize the organic fraction. By means of this instrument, the macerals were oxidized at relatively low temperatures (~200°C), leaving a residue of virtually unaltered minerals.

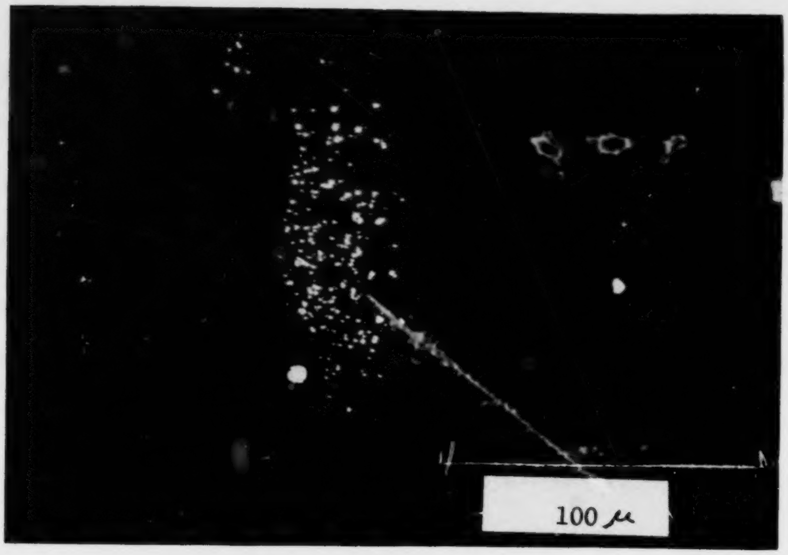

Figure 10. -- Photomicrograph of submicron crystals of pyrite (brightly reflecting grains) in vitrinite.

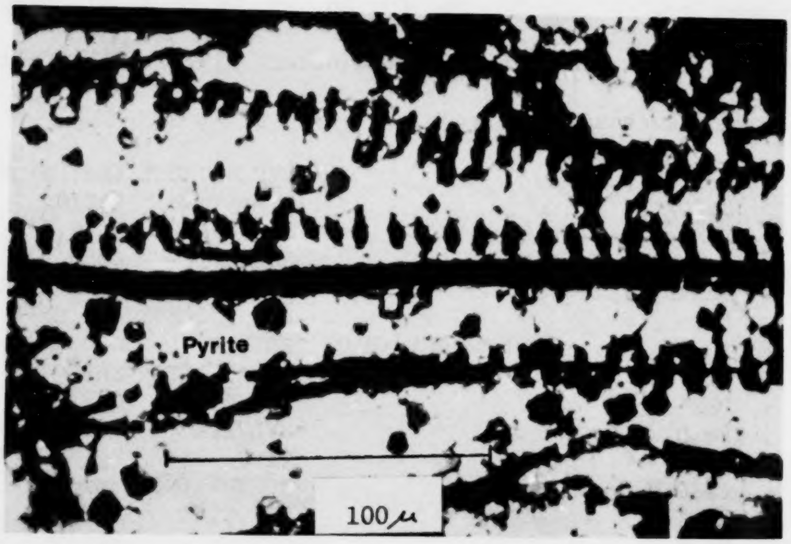

Figure 11. -- Photomicrograph of large pyrite grain showing replacement of cell wall material.

Figure 12. -- Scanning electron photomicrograph of mineral-rich zone in polished section of coal. Q, quartz; C, clay mineral; R, rutile.

Another technique that has shown great promise for the study of minerals in unashed coal is the scanning electron microscope (SEM) equipped with an energy dispersive X-ray detector, which can chemically analyze grains as small as 0.5μm (Dutcher and others 1973; Finkelman and Stanton, 1978).

Minerals in coal are 1) allogenic (transported into the peat swamp as wind or waterborne detritus) and 2) authigenic (formed in place). Authigenic minerals may precipitate from solution, result from reactions involving bacteria, or result from the oxidation, reduction or leaching of existing minerals.

A systematic relationship between certain minerals and macerals exists in many coals (Finkelman and others, 1976; Finkelman and Stanton, 1978). Dull bands in coal may consist of maceral fragments, illite, and quartz and trace amounts of rutile, zircon, rare-earth phosphates, and feldspar (fig. 13). Most fusinite and semifusinite pores are generally filled with kaolinite, but some are filled with carbonates and pyrite. The pores may also contain sphalerite (fig. 14), chalcopyrite, galena, clausthalite (fig. 15), apatite, rare-earth phosphates, and crandallite (fig. 16). Pyrite, kaolinite, micron-sized grains of sphalerite, chalcopyrite, and clausthalite may be dispersed throughout vitrinite. Barite is commonly associated with resin bodies and spores.

COAL PETROGRAPHY IN APPLIED RESEARCH

When considering the use of coal for any particular purpose, the concept of coal as a rock must be accepted. Petrographic analysis of coal has been used widely over the past two decades in predicting coke stability (Schapiro and Gray, 1964; Thompson and others, 1966) and to evaluate gasification and liquefaction potentials of coal (Given and others, 1975a).

In figure 17, several diagrams are shown for describing coal. The most conventional approach is to define the coal in terms of ash, sulfur, and combustibles on a weight-percent basis (fig. 17a and b). Through coal-petrographic analysis, the pie can be divided further into maceral groups and

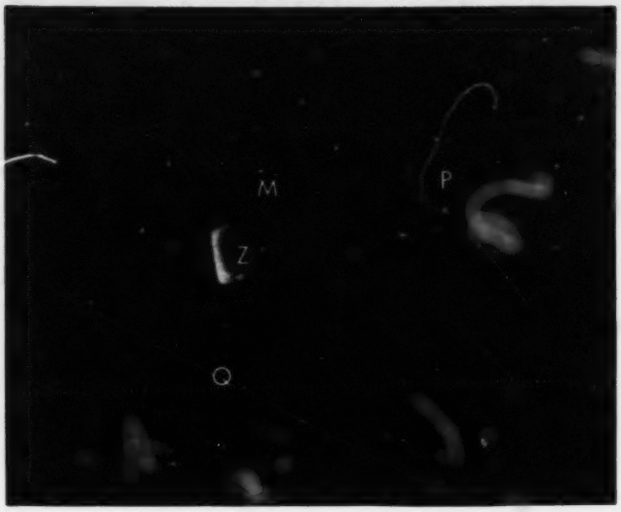

Figure 13. — Scanning electron photomicrograph of mineral-rich zone in polished section of coal. Q, quartz; P, framboidal pyrite; Z, zircon; M, maceral.

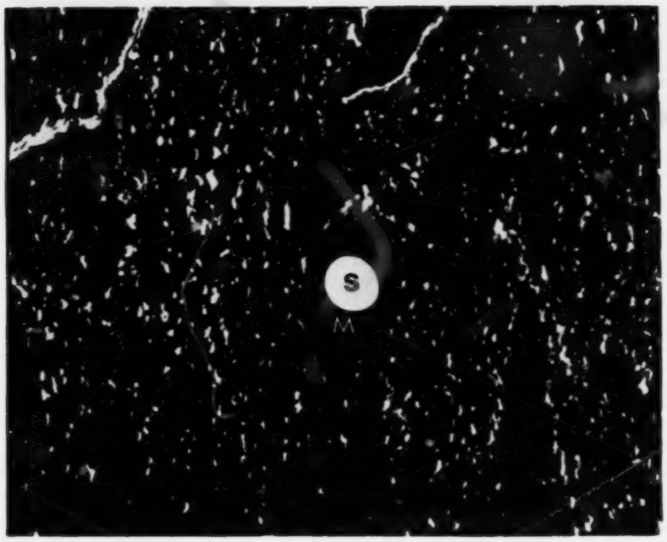

Figure 14. — Scanning electron photomicrograph of Sphalerite in organic material. S, sphalerite; M, maceral.

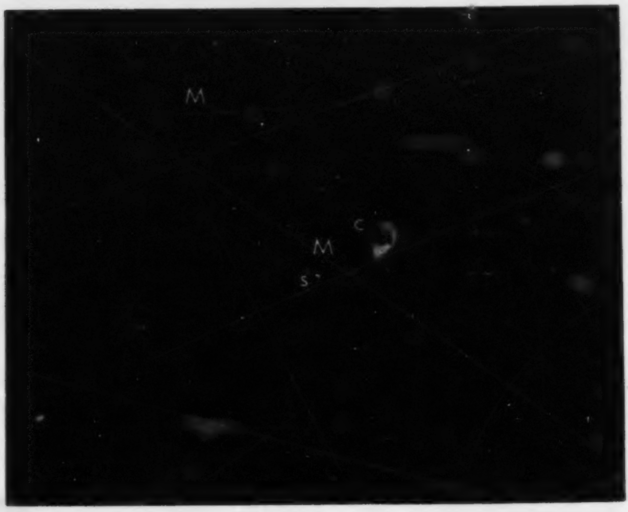

Figure 15. -- Scanning electron photomicrograph of a mineral grain in coal. C, chalcopyrite; CL, clausthalite? (PbSe); S, sphalerite; M, maceral.

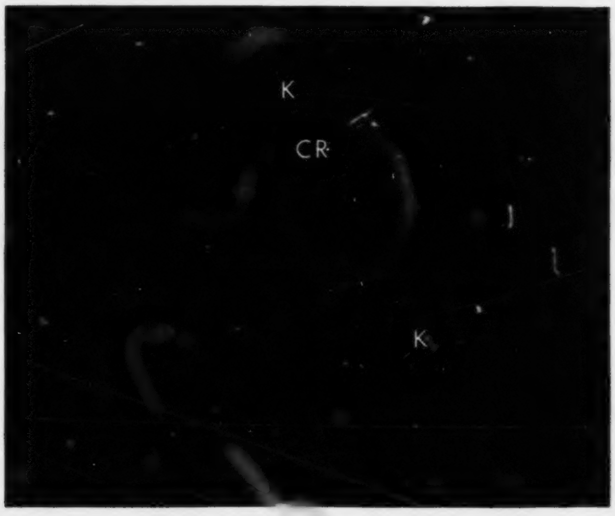

Figure 16. -- Scanning electron photomicrograph of a cell filling in fusinite. CR, crandalite; K, kaolinite.

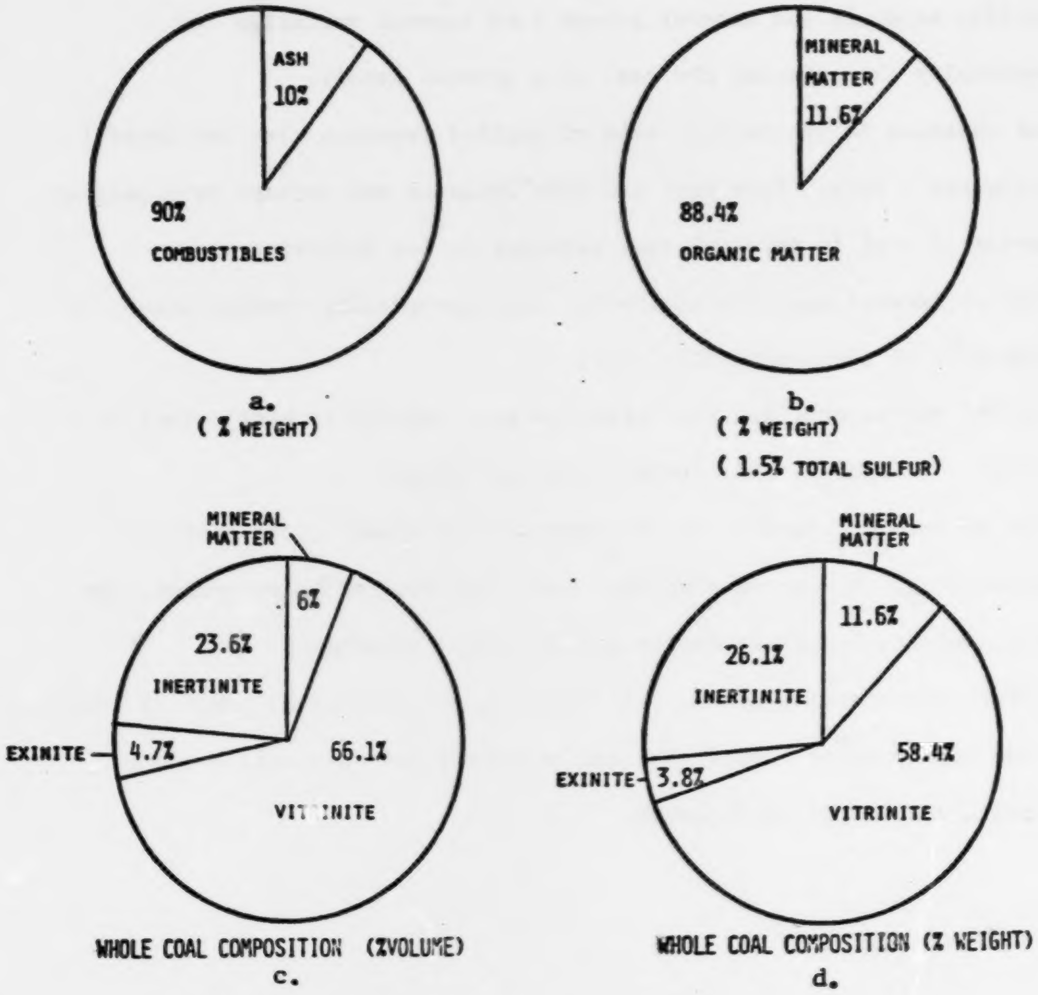

Figure 17. — Diagrams showing the composition of a bituminous coal.

mineral matter (fig. 17d). Most petrographic data is reported and used on a volume-percent basis (fig. 17c). Weight percent is calculated by using approximate maceral densities (Table 1, fig. 17d), which are not accurately known for various ranks of coal. Further subdivision of the mineral matter into specific minerals and maceral groups into maceral varieties can petrographically characterize the coal to a greater detail.

Coal cleaning is yet another area of applied research that can benefit from petrographic data. Such data can help evaluate and perhaps even predict the behavior of coal in physical coal cleaning in the following ways:

- use of maceral analyses to predict the size-gravity concentrations of the bulk of the combustible coal;
- use of microscopic mineral determinations (pyrite in particular) to predict whether and how certain coal may clean;
- use of data on specific trace elements, for example, the zinc in sphalerite, to determine whether such elements can be separated from the combustible matter during precombustion treatment.

Further understanding and applied knowledge of mineral and maceral relations in coal can help produce a fuel that can be burned and that will produce minimum pollution to the environment.

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MINERALOGIC AFFINITIES OF TRACE ELEMENTS IN COAL

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ABSTRACT

Data obtained from analyses of washed coals may be used to estimate the affinity of an element for the organic and inorganic portions of the coal. An organic affinity value is determined by normalizing the washability curves, removing from them a component that represents the contribution from inseparable mineral matter, and then calculating the area under the washability curve. The resulting value can be related to the ease with which an element can be removed from the coal by currently practical procedures for cleaning coal.

Elements can be categorized as organic, intermediate-organic, intermediate-inorganic, and inorganic. Elements grouped as inorganic are those identified in discrete mineral phases: Fe, As, Zn, Cd, and Pb as sulfides; Ca, Mg, Fe, and Mn as carbonates; Al, Si, K, and Mg as clays and silicates; Ca and P as a phosphate; and Ba as a sulfate. A considerable portion of these elements may be removed by cleaning. A number of metals, including Co, Ni, Cu, Cr, and Se have affinities in the intermediate categories, suggesting that they are present in coals either in organic association or with finely disseminated and occluded minerals within the coal. Beryllium, B, Ge, and U are present in organic association, presumably as chelated metals, and are not removed by normal cleaning procedures.

The amount of an element that is organically combined in a coal can be estimated by extrapolating the washability curve to zero percent recovery on an adjusted washability plot. Such values generally agree with those directly determined from acid-demineralized products of whole coals. When differences between those values occur, they can generally be attributed to the presence of exchangeable ions and chelated metals in the coal.

INTRODUCTION

A large portion of many potentially hazardous trace elements contained in coal may be removed by physical cleaning; however, in order to assess effectively the value of desulfurization and beneficiation procedures, it is desirable to determine baseline levels of coal contaminants and to understand their modes of occurrence.

The type of association or combination in which an element occurs in coal can significantly influence its reactivity in combustion and conversion processes. Major portions of many trace and minor elements are associated with the inorganic fraction of the coal as discrete mineral phases. Some species may be present largely or partly as ion-exchangeable cations associated with either the organics or clay minerals. To a certain extent, some elements may also be chelated or associated with stable organic complexes. The proportions of these components differ with maturation and geochemical conditions of coal formation, and, as a result, cleaning characteristics vary from one coal to another.

METHODS AND PROCEDURES

Analytical Procedures

Comprehensive trace element and mineralogical studies have been conducted to evaluate the modes of occurrence, distribution, and potential for physical removal of elements in four coals from several coal-producing areas of the United States. The following samples were selected to illustrate the wide variations in chemical and mineralogical composition encountered:

1. A high-sulfur, high-volatile "C" bituminous Illinois coal from the Herrin (No. 6) Coal Member
2. A high-sulfur, high-volatile "A" bituminous West Virginia coal from the Pittsburgh (No. 8) seam
3. A low-sulfur, medium-volatile bituminous Alabama coal from the Blue Creek seam
4. A low-sulfur, subbituminous Montana coal from the Rosebud seam

Gravity separations were made on a 3/8 inch by 28 mesh size fraction obtained by stage crushing the coal and screening. The sized coal was separated into five or six specific-gravity fractions ranging from 1.28 float to 1.60 sink in mixtures of perchloroethylene and naphtha. Representative portions of the float-sink fractions, raw coals, and 3/8 inch by 28 mesh material were stage ground to -60 mesh for low-temperature ashing and chemical analysis and to -100 mesh for trace element determinations. Representative portions of the raw coal were further ground to pass a -325 mesh screen for use in the demineralization process.

Analytical determinations of over 70 major, minor, and trace elements and other normal coal parameters were made on the whole coals, 3/8 by 28 mesh fractions, float-sink fractions, and acid-demineralized products from each coal. Procedures used to determine the elemental concentrations are described in detail in Ruch et al. (1974) and Gluskoter et al. (1977). All of the usual coal parameters were determined using the standard methods outlined in the ASTM Book of Standards, vol. 26 (1977). Trace element values are usually obtained using up to five different analytical methods on the same sample to ensure a high degree of accuracy.

Detailed mineralogic studies of single samples of the four raw coals and of the various specific gravity fractions obtained from them were conducted in conjunction with chemical analysis to identify the mineral phases present and to correlate them with the elemental content of the coals. The samples were characterized by X-ray diffraction analysis and microscopic examination of low-temperature ash residues prepared from the coals. The original minerals contained in the coal are retained by this radio-frequency plasma ashing technique, and because temperatures are sufficiently low (<150°C), the mineral phases are not significantly altered by oxidation, dehydration, or decomposition (Gluskoter, 1965). Semi-quantitative mineralogic analysis of the major nonclay minerals using an internal standard and prepared calibration curves was carried out by methods adapted from Ward (1977). Mineral phases in quantities of less than one percent were generally not detectable above background intensities. The total clay percentage was obtained by difference. Clay analysis of the <2µm fraction was conducted using the preparation and analysis methods of Stepusin (1978).

Determination of Elemental Affinities

Whether an element is concentrated in the organic or mineral matter portions of coal was determined from washability curves, which are cumulative curves based on analytical data from float-sink fractions of the coal. A washability curve with a positive slope, such as that for arsenic in figure 1a or for copper in figure 2a, indicates that the element is concentrated in the inorganic portion of the coal. The steeper the slope, the more strongly associated the element is with the mineral matter and the more readily the element can be removed from the coal with fairly high recovery. An element uniformly distributed in the various gravity fractions of the coal has a relatively flat washability curve, such as that for vanadium in figure 3a. Washing such a coal would have little effect on the concentration of the element.

Elements concentrated in the lightest specific gravity fraction may not necessarily be organically associated, however. The hypothetical elemental concentrations of the "cleaned coals" represented by washability curves extrapolated to zero percent recovery are often high because of the possible presence of finely disseminated mineral matter encapsulated within coal particles. By adjusting the curve for this component (F) using a method developed by Gluskoter et al., (1977) and described here, a more meaningful estimation of the element's concentration in the organic material can be obtained. The adjusted washability curve is constructed after determining the value for F, as in the following example for Zn, and subtracting it from each data point that was used to construct the washability curve:

$$F = \frac{LTA\%_{(\mathrm{light})}}{LTA\%_{(1.60\ s)}} \times \mathrm{Zn}_{(1.60\ s)} = \frac{6.10}{77.80} \times 250\ \mathrm{ppm} = 19.6\ \mathrm{ppm},$$

where $LTA\%_{(\mathrm{light})}$	is the percentage of low-temperature ash in the lightest float fraction (in this case, 6.10 percent),
$LTA\%_{(1.60\ s)}$	is the percentage of low-temperature ash in the 1.60 sink fraction (in this example, 77.80 percent), and
$Zn_{(1.60\ s)}$	is the elemental concentration in the 1.60 sink fraction. This sample contained 250 ppm Zn in the 1.60 sink fraction.

If the value of a datum point was negative after F was subtracted from the reported concentration, the value for that point was taken to be zero.

The area under the curve on the adjusted washability diagram is defined as the organic affinity of the element. This provides a mechanism for quantifying the data and suggests the ease with which the element can be removed from coal by gravity coal cleaning procedures. The organic affinity index was determined by calculating the area beneath a curve that had been normalized to a predetermined and constant scale and from which the component F representing the inseparable mineral matter had been subtracted. The entire normalized area of the graph is defined to be 1.00. An element that can be removed to any dgree by washing the coal has an organic affinity index less than 1.00. Extremely low values indicate that the element is present almost entirely in the mineral matter. The higher the organic affinity index, the more probability the specific element has for occurrence in organic association with the coal and the less effect washing will have on the reduction of that element in the cleaned coal. Examples of both standard and adjusted washability curves and their organic affinity indexes for the Herrin (No. 6) Coal are given in figures 1, 2, and 3 for comparison.

The affinity of an element for either the organic fraction of the coal or the mineral matter can be confirmed by utilizing a combination of physical and chemical methods to obtain an almost entirely mineral-matter-free organic fraction for direct analysis. To accomplish this, mineral matter was removed from cleaned coal by means of selective acid dissolution while the coal organic

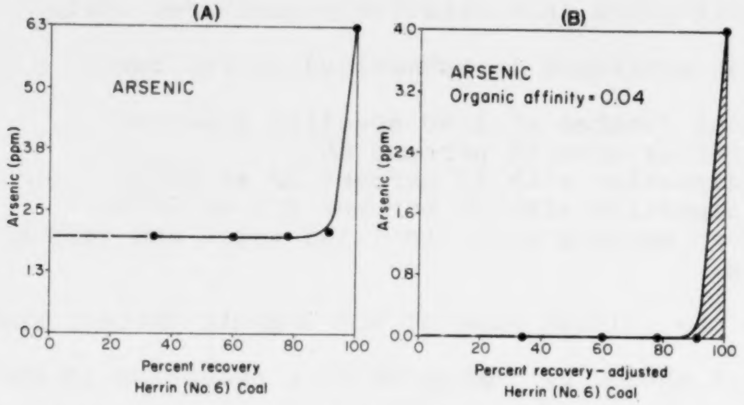

Figure 1—Arsenic in specific gravity fractions of a sample from the Herrin (No. 6) Coal Member from Illinois. (A) standard washability curve. (B) adjusted washability curve.

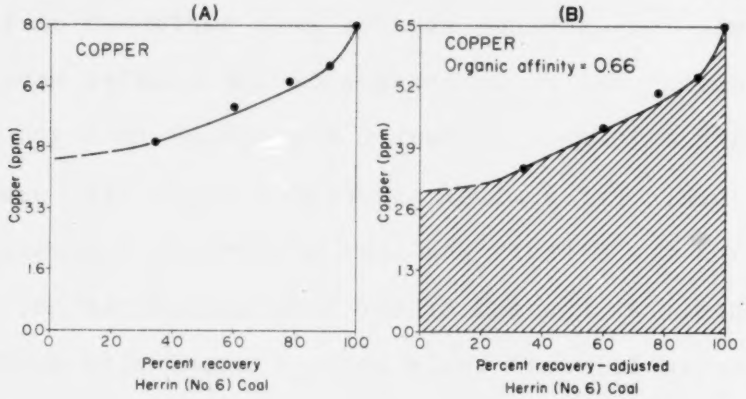

Figure 2—Copper in specific gravity fractions of a sample from the Herrin (No. 6) Coal Member from Illinois. (A) standard washability curve. (B) adjusted washability curve.

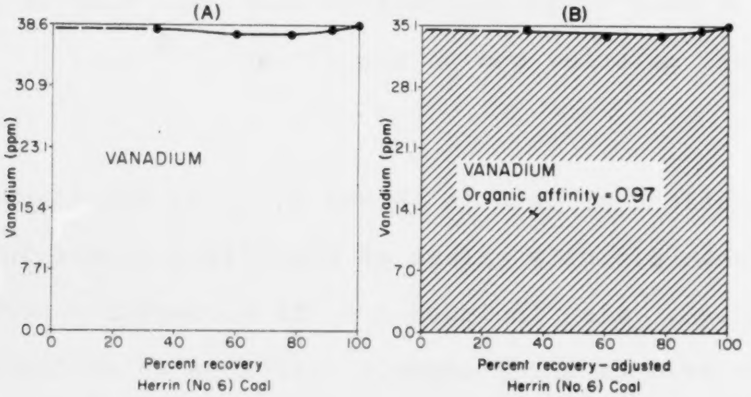

Figure 3—Vanadium in specific gravity fractions of a sample from the Herrin (No. 6) Coal Member from Illinois. (A) standard washability curve. (B) adjusted washability curve.

fraction was maintained in a relatively unaltered state. The demineralization procedure is summarized as follows:

1. Raw coal floated at 1.40 specific gravity.
2. 2-hr reflux with 10 percent HNO_3.
3. 2-hr digestion with 48 percent HF at 70°C.
4. 1-hr digestion with 25 percent HCl at 70°C.
5. Thorough washing with distilled water and vacuum drying.

This procedure may oxidize some of the organic matter; however, any major effect should be indicated by a reduction in the organic sulfur content, which in these samples is not apparent.

In order to further differentiate the way elements are held in the coal, ion-exchange studies were performed on the whole coals. Coals used for exchangeable ion studies were reduced to -325 mesh, and a 10-gram increment was placed in a 300-ml polyethylene flask. Fifty ml of ammonium acetate (1N) was added to the flask, and the mixture was then stirred at approximately 70°C for 20 hours. At the end of the dissolution period, the material was vacuum filtered while being flushed with sufficient NH_4AC solution to bring the volume up to 450 ml. A final flush with 50 ml of ethyl alcohol was performed and the sample was vacuum dried. Elemental determinations were then made on both the residual coal material and on the extract.

RESULTS

The compilations of data in tables 1, 2, 3, and 4 show the calculated organic affinity values of specific elements in the four coals studied. Also included are the elemental concentrations of raw coals as well as their organic fractions as estimated from adjusted washability curves (F/S EXT) and from direct analysis of acid demineralized (MMF) coals by the previously described

TABLE 1
Elemental concentrations and organic affinity of elements
in the Herrin (No. 6) Coal Member from Illinois (C18560)

				Organic fractions			
		Raw coal		F/S Ext[a]		MMF[b]	
Element	Organic affinity	%	ppm	%	ppm	%	ppm
Al	.30	1.40		0.10			41
Ca	.06	0.51		0			25
Fe	.06	2.60		0			66
K	.56	0.13		0.04			<1
Mg	.27	0.06		0.003			21
Na	.64	0.04		0.01			6
Ti	.29	0.06		0.13			41
Si	.45	3.20		0.017			20
LTA	.16	20.37		0			—
HTA	.16	16.46		0			—
organic S	1.11	1.87		2.33		1.81	
pyritic S	.05	4.56		0			—
sulfate S	.17	0.02		0			—
total S	.45	6.45		1.1		1.81	
Ag	.54		0.03		0.11		—
As	.04		3.4		0		<.7
B	.77		200		57		6.6
Ba	.15		54		2		0.2
Be	.87		1.4		0.64		0.03
Br	.92		13.4		12		3.3
Cd	.07		<0.10		0		<0.1
Ce	.07		25		0		0.1
Co	.74		7.2		1.7		0.36
Cr	.77		21		20		6.8
Cs	.44		2.0		0.25		0.1
Cu	.66		13		3.3		2.1
Dy	.89		1.2		0.75		0.5
Eu	.67		0.26		0.11		0.1
Ga	.15		2.4		0.30		0.73
Ge	1.76		14		1.7		—
Hf	.48		1.1		0.10		0.11
Hg	1.02		0.23		0.17		—
I	—		1.2		—		<0.8
La	.04		6.1		0		0.72
Lu	.59		0.1		0.03		0.03
Mn	.06		60		0		0.3
Ni	.75		24		5.9		<1
P	.03		50		0		<1
Pb	.32		<1.0		0.32		<1
Rb	.45		23		0.3		<1
Sb	.90		0.49		0.37		0.09
Sc	.57		4.1		0.83		0.65
Se	.28		4.3		0		0.26
Sm	.39		0.86		0.21		0.41
Sn	.16		0.40		0		<0.10
Sr	.07		33		0.8		1.5
Ta	.44		0.25		0.05		0.09
Th	.55		3.6		0.8		1.0
U	1.29		1.9		2.7		0.09
V	.97		36		35		3.5
W	—		0.59		—		0.06
Yb	.52		0.84		0.18		0.23
Zn	.04		57		0		1
Zr	.49		32		9		—

[a] Float-sink extrapolation

[b] Acid-demineralized coal

TABLE 2
Elemental concentrations and organic affinity of elements in the Pittsburgh (No. 8) seam from West Virginia (C19824)

				Organic Fractions			
	Organic	Raw coal		F/S Ext[a]		MMF[b]	
Element	affinity	%	ppm	%	ppm	%	ppm
Al	.62	1.02		0.43			41
Ca	.04	1.61		0			30
Fe	.17	1.12		0			80
K	.10	0.102		0			2.5
Mg	.04	0.16		0			<20
Na	.71	0.068		0.036			8.8
Si	.39	1.95		0.33			40
Ti	.58	0.06		0.023			11
HTA	.15	12.87		0			—
LTA	.13	13.09		0			—
organic S	1.15	1.10		1.67			—
pyritic S	.18	1.08		0			—
sulfate S	.12	0.05		0			—
total S	.81	2.23		1.65			—
As	.11		3.9		0		0.09
B	1.14		82		86		—
Ba	.90		130		100		27
Be	.77		0.45		0.26		0.07
Br	1.02		12		12		12
Cd	.09		0.24		0		<.05
Ce	.68		16		6.2		2.5
Co	.79		2.2		1.5		0.25
Cr	.58		14		5.0		2.0
Cs	.28		0.76		0.07		0.03
Cu	.49		8.6		2.1		1.5
Dy	.67		0.82		0.41		0.48
Eu	.67		0.18		0.11		0.06
Ga	.79		2.6		2.1		1.4
Ge	.41		0.80		0.29		0.27
Hf	.40		1.0		0.15		0.6
Hg	.47		0.13		0.03		0.03
I	.67		0.3		0.14		0.14
In	—		0.02		—		<.1
La	.68		5.7		3.0		2.6
Lu	.62		0.08		0.03		0.02
Mn	.06		35		0		0.68
Mo	.04		1.66		0		<0.2
Ni	.62		9.0		2.6		1.2
P	.68		103		42		<5
Pb	.04		25		0		<1
Rb	.18		9.5		0		<1
Sb	.37		1.6		0.17		0.85
Sc	.67		2.3		1.1		0.08
Se	.53		1.6		0.7		0.5
Sm	.72		0.94		0.52		0.47
Sn	.08		7.8		0.02		1.0
Sr	.94		143		0.11		24
Ta	.51		0.17		0.04		0.08
Tb	.90		0.13		0.11		0.04
Th	.62		2.1		0.66		1.1
Tl	.06		0.54		0		<0.1
U	.74		0.60		0.74		0.11
V	.57		17		6.6		2.7
W	.67		0.26		0.15		<0.9
Yb	.74		0.30		0.23		0.13
Zn	.31		10.3		0.85		<1
Zr	.27		30		1.2		<1

[a] Float-sink extrapolation

[b] Acid-demineralized coal

TABLE 3
Elemental concentrations and organic affinity of elements in the Blue Creek seam from Alabama (C18848)

				Organic fractions			
		Raw coal		F/S Ext[a]		MMF[b]	
Element	Organic affinity	%	ppm	%	ppm	%	ppm
Al	.40	1.90		0.25			240
Ca	.34	0.35		0.037			48
Fe	.44	0.70		0.14			54
K	.12	0.28		0			2.3
Mg	.07	0.05		0			<20
Na	.20	0.030		0			<3
Si	.17	2.80		0			64
Ti	.54	0.15		0.04			28
HTA	.17	11.65		0			—
LTA	.19	12.67		0			—
organic S	1.08	0.50		0.53		0.33	
pyritic S	.63	0.04		0.02			—
sulfate S	1.05	0.01		0.012			—
total S	1.08	0.55		0.56		0.36	
Ag	.73		0.01		0.007		—
As	.05		1.8		0		<0.1
B	.37		15		0.76		5.1
Ba	.62		230		76		20
Be	.76		0.68		0.36		0.05
Br	1.20		2.5		2.5		1.7
Cd	.45		<0.10		0.05		<0.1
Ce	.64		30		14		3.5
Co	1.08		9.4		7.9		10
Cr	.60		21		7.1		14
Cs	.10		2.3		0		0.05
Cu	.78		12		8.0		4.1
Dy	.78		2.1		1.5		0.90
Eu	.78		0.44		0.20		0.13
Ga	.64		6.3		2.6		0.06
Ge	1.10		0.60		0.18		—
Hf	.44		1.2		0.33		0.33
Hg	1.02		0.39		0.04		—
I	—		1.3		—		0.5
In	—		0.32		—		<0.1
La	.74		18		9.6		2.8
Lu	.69		0.13		0.04		0.07
Mn	.05		13		0		<1
Ni	1.01		11		9.9		1
P	.60		190		90		<4
Pb	.68		12		1.9		<1
Rb	.10		18		0		<1
Sb	.64		0.82		0.23		0.73
Sc	.53		4.3		1.2		2.5
Se	.58		3.0		0.9		0.56
Sm	.66		2.8		1.0		0.06
Sn	.68		0.50		0.19		<0.2
Sr	.80		130		54		40
Ta	.34		1.1		0.04		<0.07
Tb	.66		0.22		0.20		0.29
Th	.43		5.4		0.61		0.02
U	.71		0.92		0.77		0.3
V	.75		54		29		<5
W	.70		0.36		0.30		0.1
Yb	.56		0.92		0.18		0.60
Zn	.21		2.0		0		<1
Zr	.60		57		21		—

[a] Float-sink extrapolation

[b] Acid-demineralized coal

TABLE 4
Elemental concentrations and organic affinity of elements in the Rosebud seam from Montana (C19854)

				Organic fractions			
	Organic	Raw coal		F/S Ext[a]		MMF[b]	
Element	affinity	%	ppm	%	ppm	%	ppm
Al	.18	1.15		0			20
Ca	.82	0.97		0.43			20
Fe	.02	0.47		0			35
K	.02	0.079		0			5
Mg	.97	0.44		0.32			20
Na	.88	0.019		0.009			15
Ti	.15	0.05		0			4
Si	.06	2.41		0			30
LTA	.12	14.49		0			—
HTA	.07	12.09		0			—
organic S	1.10	0.62		0.53			—
pyritic S	.02	0.22		0			—
sulfate S	.02	0.06		0			—
total S	.74*	.90		0.59			—
As	.03		0.69		0		1.3
B	1.24		100		115		—
Ba	.02		808		0		40
Be	.73		0.47		0.14		0.03
Br	.99		1.6		5.0		4.5
Cd	.06		0.22		0		<0.07
Ce	.89		10.3		5.3		3.3
Co	.80		1.2		0.57		0.9
Cr	.09		6.2		0		0.62
Cs	.03		0.43		0		<0.04
Cu	.44		8.8		1.2		1.8
Dy	.77		0.6		0.28		0.23
Eu	.89				0.09		0.04
F	.76				14		—
Ga	.76		3.3		1.7		2.2
Ge	.74		0.90		0.31		0.32
Hf	.39		1.2		0.17		0.2
Hg	.03		0.06		0		0.02
I	.02		0.3		0		0.02
La	.90		5.2		3.1		1.3
Li	.14		14.4		0		—
Lu	.68		0.06		0.02		0.03
Mn	.04		85		0		1.5
Mo	.83		7.1		2.6		1.4
Ni	.64		3.1		0.84		3.0
P	1.02		121		95		<5
Pb	.04		4.6		0		<1
Rb	.03		3.3		0		0.7
Sb	.95				0.50		0.73
Sc	.78		1.6		0.71		0.6
Se	.05		0.93		0		0.73
Sm	.73		0.86		0.30		0.25
Sn	.04		8.1		0		1.8
Sr	.98		103		94		4.4
Ta	.61		0.13		0.5		0.11
Tb	.79		0.11		0.5		0.05
Te	—		<1		—		—
Th	.56		2.5		0.6		0.78
Tl	.11		0.46		0		<0.1
U	.58		1.5		0.25		0.2
V	.60		10.6		2.3		1.2
W	1.15		0.70		.70		0.06
Yb	.74		0.25		.13		0.19
Zn	.02		4.3		0		<0.3
Zr	.04		31		0		<2.0

[a] Float-sink extrapolation

[b] Acid-demineralized coal

procedures. Comparison of concentrations between the F/S EXT and MMF shows that the majority are in close agreement and are within the precision of the analytical methods.

The following summarizes the mineral phases detected in low-temperature ashes from the four coals studied:

1. Herrin (No. 6) Coal Member, Illinois—kaolinite, illite, mixed-layer clay, pyrite, quartz, calcite; traces of apatite, marcasite, szomolnokite, gypsum.
2. Pittsburgh (No. 8) coal, West Virginia—kaolinite, illite, mixed-layer clay, pyrite, quartz, calcite; traces of dolomite, orthoclase, szomolnokite, sphalerite, rutile, galena.
3. Blue Creek seam, Alabama—major kaolinite; muscovite, quartz, siderite, calcite; traces of pyrite, apatite.
4. Rosebud seam, Montana—kaolinite, illite, mixed-layer clay, quartz, pyrite, calcite, bassanite; traces of barite, chlorite.

The results of semi-quantitative mineralogic analysis are presented in table 5. Percentages of pyrite, quartz, calcite, total clays, and other minor minerals present in the low-temperature ashes are given for the whole coals and their various specific gravity fractions. Results of additional clay analysis of the West Virginia and Montana coals are given in table 6. Due to the inherent problems involved with clay mineral preparation and analysis, these data are given to indicate the general trends and are semi-quantitative at best.

The values given in tables 1 through 6 are not meant to represent the regional trace element and mineral contents for the given coal seams because the actual amounts present vary from sample to sample. It should be noted that amounts also vary with the separatory methods and analytical techniques used.

Data are presented in table 7 indicating the concentrations of major exchangeable ions found in the original coal, the residue after ammonium acetate extraction, and the extracted solution found in three of the coals studied. Data for the Illinois coal studied are

TABLE 5
Results of mineralogical analysis

	Sample #	Fraction	Recovery (%)	LTA (%)	Pyrite (%)	Calcite (%)	Qtz (%)	Siderite (%)	Barite (%)	Bassanite (%)	Apatite (%)	Clays (%)
					Average mineral percentages ±7.5 % in low temperature ash (LTA)							
Herrin (No. 6), Illinois	C18560	Raw coal	—	20.37	39	5	14	—	—	—	—	42
	C18562	28M x 0	—	25.17	28	6	14	—	—	—	—	51
	C18563	1.29F	34.3	6.10	19	3	16	—	—	—	—	62
	C18564	1.33FS	25.9	9.81	22	3	16	—	—	—	—	59
	C18565	1.40FS	18.6	17.62	23	2	18	—	—	—	—	57
	C18566	1.60FS	12.5	26.48	31	2	27	—	—	—	—	40
	C18567	1.60S	8.7	77.80	49	10	9	—	—	—	<1	32
Blue Creek, Alabama	C18848	Raw coal	—	12.67	<1	4	8	2	—	—	<1	85
	C18889	28M x 0	—	11.38	<1	4	10	3	—	—	<1	82
	C18878	1.30F	25.3	3.76	<1	4	4	1	—	—	<1	90
	C18879	1.32FS	20.5	6.15	<1	4	4	3	—	—	<1	88
	C18880	140FS	36.0	9.71	<1	4	9	3	—	—	<1	83
	C18881	1.60FS	11.8	19.76	<1	6	7	6	—	—	<1	80
	C18882	1.60S	6.4	59.75	<1	6	26	9	—	—	<1	58
Rosebud, Montana	C19854	Raw coal	—	13.09	3	4	13	—	—	16	—	64
	C19848	1.301F	36.8	7.41	<1	<2	9	—	—	20	—	68
	C19849	1.32FS	24.4	9.46	<1	<3	12	—	—	14	—	70
	C19850	1.35FS	13.1	6.91	<1	<3	10	—	—	20	—	66
	C19851	1.40FS	12.3	11.35	<1	<7	13	—	—	18	—	61
	C19852	1.60FS	10.4	20.53	<1	10	20	—	—	9	—	60
	C19853	1.60S	3.0	62.88	28	10	20	—	1	0	—	41
Pittsburgh (No. 8), West Virginia	C19824	Raw coal	—	14.49	16	22	8	—	—	—	—	54
	C19827	1.275F	27.8	5.11	10	2	7	—	—	—	—	81
	C19828	1.292F	26.5	6.42	13	3	7	—	—	—	—	77
	C19829	1.32FS	19.7	9.28	18	2	6	—	—	—	—	74
	C19830	1.40FS	13.3	14.01	21	3	9	—	—	—	—	67
	C19831	1.60FS	5.5	24.14	30	7	14	—	—	—	—	49
	C19832	1.60S	7.2	80.04	14	60	10	—	—	—	—	16

TABLE 6

Results of clay mineral analysis (<2 μm fraction of LTA) of selected coals

	Sample #	Fraction	Illite (%)	Kaolinite (%)	Mixed layer clays (%)	Chlorite (%)
Pittsburgh (No. 8), West Virginia	C19824	Raw coal	26	47	27	—
	C19827	1.275F	20	60	20	—
	C19828	1.292FS	21	65	14	—
	C19829	1.32FS	21	62	17	—
	C19830	1.40FS	21	55	24	—
	C19831	1.60FS	25	38	37	—
	C19832	1.60S	33	19	48	—
Rosebud, Montana	C19854	Raw coal	17	64	11	8
	C19848	1.301F	17	68	5	10
	C19849	1.32FS	12	71	9	8
	C19850	1.35FS	16	77	7	—
	C19851	1.40FS	17	71	12	—
	C19852	1.60FS	20	67	13	—
	C19853	1.60S	28	56	16	—

TABLE 7

Comparison of elemental concentration
in ammonium acetate extracted (ion-exchanged) samples

Element	C-19824 Pittsburgh (No.8) Original coal (%)	Residue (%)	Removed[a] in NH_4AC (ppm)	C-19854 Rosebud Original coal (%)	Residue (%)	Removed[a] in NH_4AC	C-18848 Blue Creek Original coal	Residue	Removed[a] in NH_4AC (ppm)
Si	2.12	2.17	—	2.41	2.42	—	1.72%	1.71%	—
Al	1.10	1.11	—	1.15	1.16	—	1.44%	1.45%	—
Mg	.16	.14	40	.44	.11	.27%	.02%	.02%	<1
Na	.07	.04	300	.019	.00	200 ppm	170 ppm	140 ppm	<8
K	.10	.10	<2	.08	.08	12 ppm	1000 ppm	1000 ppm	.1
Ca	1.21	1.06	989	.97	.28	.53%	.09%	.06%	134
Fe	1.07	1.12	—	.49	.59	—	.36%	.36%	—
Ti	.057	.054	—	.06	.07	—	.13%	.13%	—
P	.012	.011	—	.012	.012	—	190 ppm	204 ppm	—
	(ppm)	(ppm)	(ppm)	(ppm)	(ppm)				(ppm)
V	17	17	—	10	12	—	52 ppm	53 ppm	—
Cl	1400	676	778	75	24	50	.02%	.01%	—
Li	6.7	6.9	< .3	14.4	14	< .3	—	—	—
Be	.28	.30	< .8	47	45	< .8			
Sr	129	130	<4	103	50	67	122 ppm	120 ppm	<1
Ba	121	109	10	808	700	86	170 ppm	155 ppm	16
B	82	21		100	10				

[a] Values actually found in the extract.

not available at this time. Because different amounts of specific ions may be exchanged by various media, the data presented here can be interpreted to indicate only the relative potential for removal.

DISCUSSION

Dozens of minerals have been reported in coals. Sulfides, sulfates, carbonates, quartz and clay minerals, together with many trace minerals, form a multi-component system with complex origins and variable chemical compositions. The chemical elements present in the mineral matter occur not only as major components of minerals, but also to a limited extent as isomorphic replacements, in solid solution or as exchangeable cations on clays. These types of sites in the mineral matter are presumably the position of many of the trace elements found in coals.

Table 8 surveys the principal minerals commonly found in coals and some of the trace elements potentially associated with them. Specific associations have been compiled from the results of trace element investigations of coals (Gluskoter et al., 1977; O'Gorman and Walker, 1972; Miller and Given, 1978) as well as from reviews of basic geochemical and mineral research (Deere et al., 1966; Weaver and Pollard, 1973; and Grim, 1968). This partial listing does not preclude the probability of additional mineral matter-trace element associations.

Sulfides. In addition to the sulfides listed in table 8, trace amounts of millerite (NiS), cinnabar (HgS), and galena (PbS) have been reported in coals, and undoubtedly more sulfide phases will be documented in the future with the use of advanced electron microscope methods. Iron is the dominant element in the sulfide

TABLE 8
Elements potentially associated with minerals commonly found in coals

Mineral phases	Major constituents	Trace constituents
Sulfides		
Pyrite, marcasite	Fe, S	As, Cd, Hg, Ag, Pb, Fe, Zn, Cu, Co, Sn, Ni, Mo, Se, Ga
Sphalerite	Zn, S	
Chalcopyrite	Cu, Fe, S	
Galena	Pb, S	
Sulfates		
Barite	Ba, S	Sr, Pb, Ca
Gypsum	Ca, S	
Carbonates		
Calcite	Ca	Ba, Sr, Pb, Mn, Ca Fe, Mg
Siderite	Fe	
Ankerite	Ca, Fe	
Dolomite	Ca, Mg	
Phosphates		
Apatite	Ca, P, F	Mn, Cl, Mg, Ce, other rare earths
Silicates		
Quartz	Si	
Zircon	Si, Zr	Hf, Th, P
Tourmaline	Ca, Mg, Fe, B, Al, Si	Li, F
Plagioclase	Ca, Na, Al, Si	Ba, Sr, Mn, Ti, Fe, Mg
Orthoclase	K, Al, Si	Rb, Ba, Sr, Fe, Mg, Ti, Li
Muscovite	K, Al, Si	F, Rb, Ba, Sr
Clay minerals		
Kaolinite	Al, Si	Ti
Illite	Al, Si, K	Fe, Mg, Ca, Na, K, Ti, Li, V, B, Mn, Cr, Cu, Ni, Rb, Cs, Ga, Zn, Se, F, La, Ba, Sr, Co, and others
Montmorillonite	Al, Si, Mg, Fe	
Mixed layer clays	Al, Si, K, Mg, Fe	
Chlorite	Al, Si, Fe, Mn, Mg	

NOTE: This partial listing does not preclude the probability of additional mineral-trace element associations.

group, usually occurring with Zn and Cu in solid solution; the associated chalcophile elements listed can also be present in small amounts in sulfide minerals. For example, analyses of sphalerite from coals in northwestern Illinois have revealed 0.15 to 0.93 percent Fe, 0.30 to 0.56 percent Cd, 360-470 ppm Cu, <10 to 440 ppm Ni, 33 to 110 ppm Ga, and lesser amounts of other elements (Cobb et al., 1978).

Carbonates. Calcite and siderite are the most common carbonate minerals present in U.S. coals, although ankerite and dolomite are more frequently reported worldwide. Compositions of carbonate minerals vary appreciably because of the extensive solid solution series of calcium, iron, and magnesium. In addition, small amounts of Mn, Sr, and Ba may replace the major cations in the crystal lattice and are commonly reported in chemical analyses of carbonate minerals.

Clay minerals. Kaolinite, illite, and mixed-layered illite-montmorillonite clays commonly make up a major portion of the mineral matter of most coals. Cation absorption and exchange are important properties of these minerals and the minor and trace alkali and alkaline earth elements are favored for the exchangeable sites in clays. Due to inherent higher cation-exchange capacities, illites, montmorillonites, and mixed-layered clays tend to absorb a greater variety of ions than kaolinite. A number of elements are also known to substitute for Al, Si, and other major constituents bound into the crystal lattice. Trace element analyses of partings and shale strata associated with coal seams indicate higher concentrations of many minor and trace elements in these components but because of the complex combinations of clays and other incorporated minerals, specific mineral-trace element associations are not conclusive.

With the exception of quartz, many of the other minerals listed occur only in trace amounts in most coals. Most of their trace element associations are due to isomorphic substitution of preferred ions in the crystal lattice.

Mineral analyses show that certain mineral phases are ubiquitous in these coals, although the amount and proportions of these minerals vary because of individual variations related to rank, geological conditions, and the geochemical environment. In general, the percentages of pyrite, calcite, quartz, and most of the minor minerals increase in the heavier gravity fractions as the relative percentage of total clays in the mineral matter decreases. The exception, bassanite, is not a naturally occurring mineral in coals and forms during low-temperature ashing preparation by the fixation of organic sulfur with exchangeable Ca cations derived from organic carboxyl groups in low-rank coals (Miller and Given, 1978).

The low-temperature ash of whole coals shows significant variation in total clay content, ranging from 42 percent to 85 percent. Increased percentages of the mineral matter in the lighter gravity fractions of the coal is composed of clays finely dispersed within the macerals. Compositional trends of the two coals selected for additional clay analysis show higher proportions of kaolinite in the mineral matter portions of the lighter fractions and increased amounts of illite and mixed-layer clays in the 1.60 sink fraction. Such variations have a practical importance for utilization. The composition of the clay minerals in coals affects the fusion temperature of the resulting ash. White (1964) has indicated that increased concentrations of illite, especially in conjunction with higher amounts of carbonate, lowers the melting point and viscosity and changes the glass-forming characteristics of the ash. If a portion of the clays is removed during cleaning, the resultant clay composition may substantially change, altering trace element contents and adsorption properties as well as the fusion and sintering characteristics of the ash.

Washability curves prepared from the mineral data are shown in figures 4, 5, 6, and 7. They indicate that a large portion of the pyrite and calcite in the four coals studied can be concentrated and removed through physical cleaning methods; removal of quartz and clay minerals is not as effective as removal of the heavier minerals.

From the information presented in the preceding tables some conclusions can be drawn regarding the distributions of a number of elements and their potential for removal during coal cleaning. An inspection of the data in table 9 indicates the wide variation in the organic association of trace elements in coals. For the coals selected in this study, only Br, Ge, and organic S are consistently in the most organic category. This indicates that these elements cannot be removed to any degree by specific-gravity cleaning procedures. Only Mn and As show great inorganic affinity in all coals and therefore can be most easily removed. A number of other elements—Sn, K, Pb, P, Zr, Se, Ti, Li, Al, Hf, Cs, Si, Cd, Fe, Zn, and pyritic S—all of which can be related to discrete mineral phases—show a consistently high degree of cleaning potential, whereas Hg, sulfate S, Sr, Ba, Ga, Na,

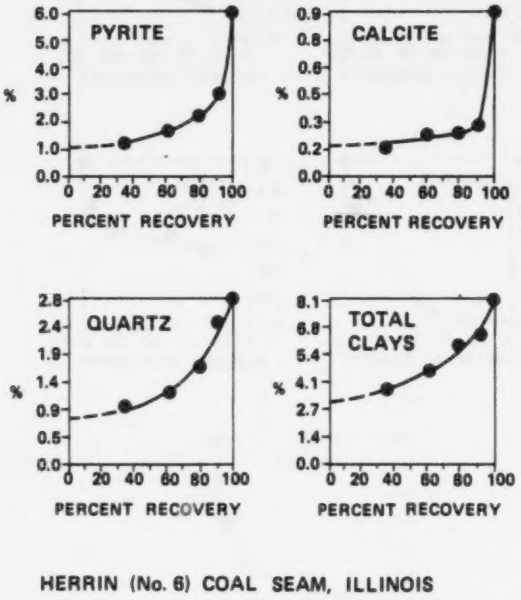

Figure 4—Mineral distributions in a single sample of the Herrin (No. 6) Coal Member, Illinois.

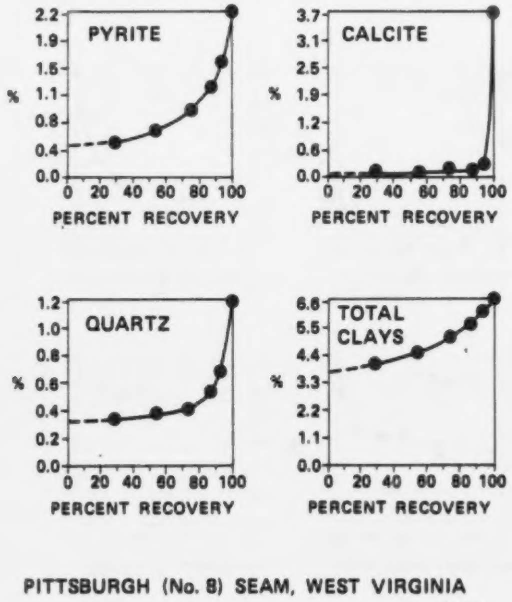

Figure 5—Mineral distributions in a single sample of the Pittsburgh (No. 8) seam, West Virginia.

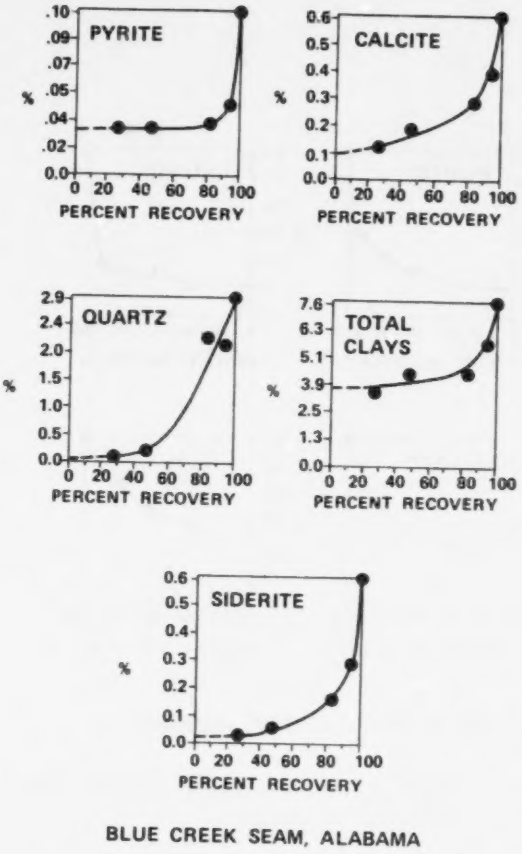

Figure 6—Mineral distributions in a single sample of the Blue Creek seam, Alabama.

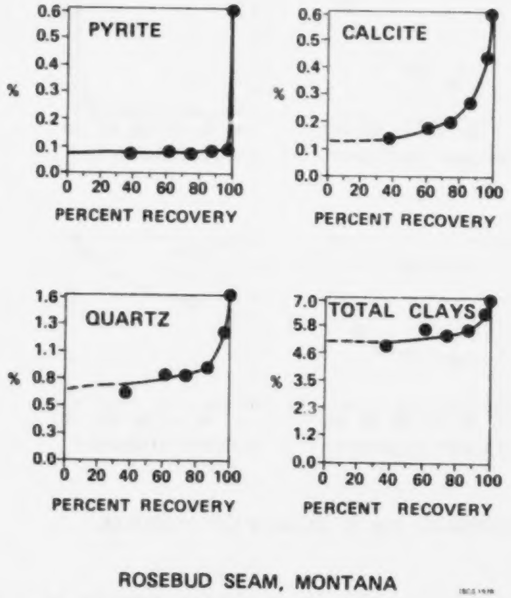

Figure 7—Mineral distributions in a single sample of the Rosebud seam, Montana.

TABLE 9
Ranking of elemental organic affinities determined from prepared washed coals

Herrin (No. 6) seam, Illinois		Blue Creek seam, Alabama		Pittsburgh (No. 8) seam, West Virginia		Rosebud seam, Montana	
ORGANIC							
Ge	1.76	Br	1.20	ORS	1.15	B, Na	1.24
U		Ge		B		W, Mo	
ORS		Co		Br		ORS	
Hg		ORS, TOS		Sr		Br, Ge, Yb	
V		SUS		Ba		Sr, TOS	
Br		Hg		TOS		Mg, Sm	
Sb		Ni	.91	Co, Ga		Sb, La	
Dy				Be	.71	Ce, Lu	
Be	.87			U		Ca	
				Sm, Na		Co	
				Yb		Tb	
						Sc	
						Dy	
						F, Ga	
						Be	
						Sb	.72
INTERMEDIATE ORGANIC							
B, Cr	.77	Sr	.80	Ce, La, P	.69	Lu	.68
Ni		Cu, Dy		Dy, Eu, I, Sc		Ni	
Co		Be		W, Li		Ta	
Eu		V		Lu, Ni, Th, Al		V	
Cu		La		Cr, Ti, V		U	
Na		Ag		Se, Ta	.51	Th	.54
Lu		U					
Sc		W					
K		Lu					
Th		Pb, Sn					
Ag		Sm, Tb					
Yb	.52	Eu, Ga, Sb, Ce					
		PYS					
		Ba					
		Cr, P, Zr					
		Se					
		Yb					
		Ti					
		Sc	.53				
INTERMEDIATE INORGANIC							
Zr	.49	Cd	.45	Du	.50	Cu	.44
Hf		Hf, Fe		Hg		Hf	
TOS, Rb, Ti		Th		Hf, Si			.54
Cs, Ta		Al		Sb, Zn			
Sm		B		Cs			
Pb		Ta, Ca	.34	Zr	.27		
Al							
Si							
Se							
Mg	.27						
INORGANIC							
SUS	.17	Zn	.21	Rb, PYS	.19	Al	.18
Sn, HTA, LTA		Na		Fe		Ti	
Ba, Ga		LTA		HTA		Li	
Cd, Ce, Sr		HTA, Si		SUS		LTA	
Mn, Ca, Fe		K		As		Tl	
PYS		Cs, Rb		K		Cr	
As, La, Zn		Mg		Cd		HTA	
P	.03	As, Mn	.05	Sn		Cd, Si	
				Mn, Tl, Mg		Se	
				Mo, Pb, Ca	.05	Mn, Pb, Sn, Zr	
						As, Cs, Hg, Rb	
						PYS, Ba, I, Zn, Fe, K, SUS	.02

NOTE: Elements are arbitrarily grouped according to calculated organic affinity index for individual coals.

Mo, La, Mg, Cd, and Ca exhibit a high degree of variability in cleaning potential depending upon the coal studied. Most other elements such as U, V, Dy, Be, Cr, Co, Ni, Yb, W, Lu, Tb, Sc, Sb, S, B, Sm, Eu, Ag, Cu, and Th are consistently in the intermediate grouping where partial cleaning by physical methods can be accomplished without losing a major portion of the coal. It is further apparent that low-rank coals contain the largest number of elements not readily removed. Since these elements in many cases are at rather low concentrations, they may not present a significant problem.

The potential cleaning of elements and minerals is dependent on other parameters in addition to the organic-inorganic associations. The particle size of the minerals plays a significant role in the ease of cleaning. For example, scanning electron microscope studies indicate that 95 percent of the pyrite occurring in this Pittsburgh (No. 8) coal is encapsulated within the coal particles and has an average particle size of 8µm. The broadness of the pyrite washability curve in figure 5 reflects this relationship. Furthermore, if an element such as Mn occurs in association with calcite, it is easier to remove than if it occurs only in clay minerals.

The organic affinity can therefore be used only as an indicator of cleaning potential; it is not absolute. Neither does the calculated organic affinity value necessarily bear any relation to the percentage of that element associated with the organic fraction of the coal.

The agreement between the concentrations of elements as extrapolated from float-sink data and the values determined from demineralized material(tables 1, 2, 3, and 4) is within analytical and sampling errors in most cases. Variations greater than expected from these causes are exhibited by some elements, however. Although a number of factors could influence this difference, the presence of exchangeable cations has been shown to be the primary cause. The values given in table 7 indicate the exchanges that can occur and show the levels of removal that may be effected. An example of this exchangeability is shown in figure 8, where it can be observed that the exchangeable Ca in the three coals is approximately equal to the difference between the F/S EXT and the MMF values in tables 2, 3, and 4. The Rosebud coal has by far the greatest amount of exchangeable calcium. This pattern holds true in a general way for most of the differences between the values obtained by those procedures. Although chelated or organically associated elements may be stripped off the organic molecule during demineralization, especially in low-rank coals, this factor is not often significant.

Although many elements have at least a limited organic association, it should be noted that the total ash content of acid-demineralized coals seldom exceeds 250 to 600 ppm. Addition of the exchangeable, soluble, and chelated elements still results in the conclusion that most of the trace and minor elements in coal are in a mineral form and subject to significant reduction by physical cleaning procedures.

SUMMARY

Data from analyses of whole coals and their specific gravity fractions may be used to predict the organic-inorganic associations of trace elements in coal and to yield information about the potential for cleaning these fuels by specific gravity procedures.

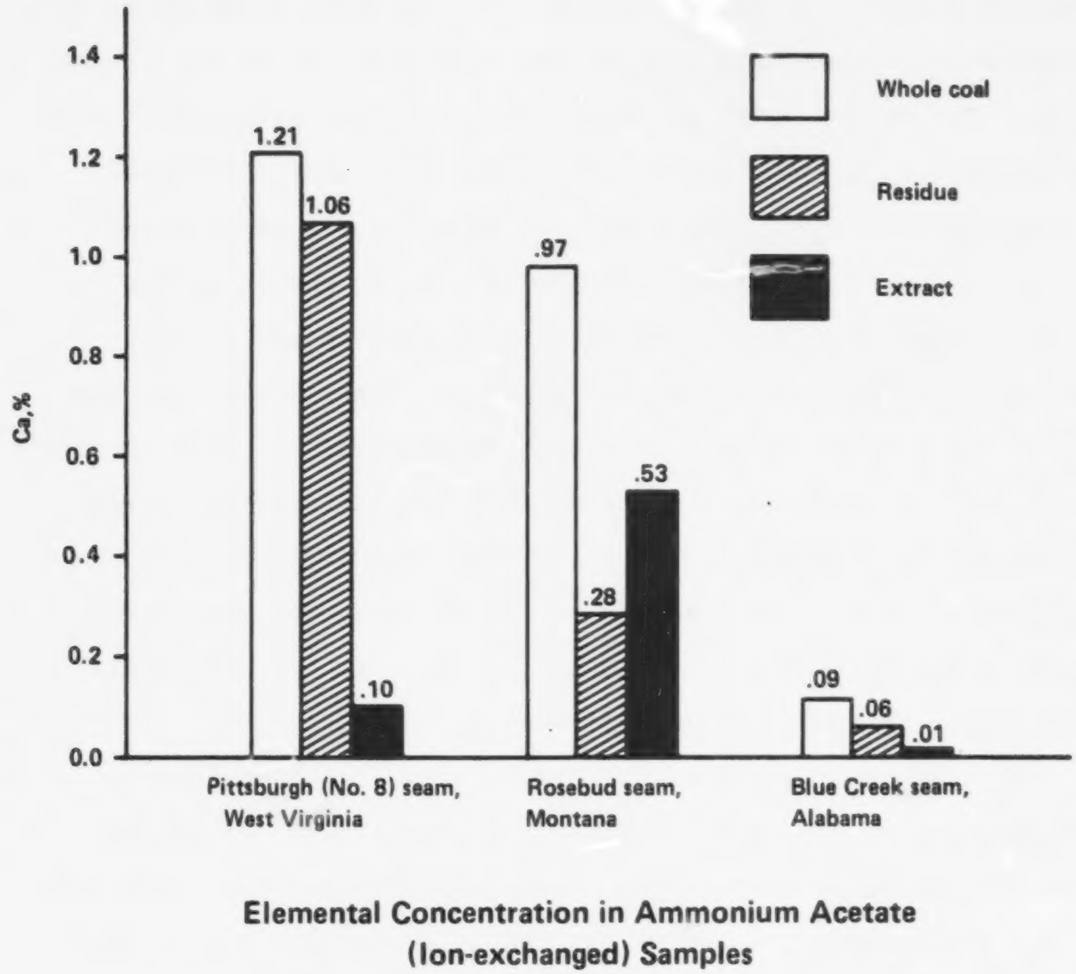

Figure 8—Elemental concentration of calcium in ammonium acetate (ion-exchanged) samples.

The acid-demineralized data can be used to estimate the total cleaning that can be achieved by a combination of physical and chemical separation methods.

The elements with low organic affinity are concentrated in mineral phases that have been identified in the heaviest washed coal fractions: Fe, Zn, Cd, Pb, As, and pyritic S occur as sulfide minerals; Ca, Mg, Fe, and Mn occur as carbonate phases; Al, Si, K, and Mg occur as clays and silicates; Ca and P occur as a phosphate; and Ba has been identified as a sulfate.

Although some elements with high organic affinities cannot be beneficiated by float-sink procedures, they do not constitute a major portion of the trace and minor element content of most coals.

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EFFECTS OF COAL CLEANING ON ELEMENTAL DISTRIBUTIONS

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ABSTRACT

The coal industry, through its research affiliate Bituminous Coal Research, Inc., has established a program for obtaining valid information concerning potential trace element problems as they relate to coal. One means of controlling trace element emissions is to remove these trace constituents prior to combustion during the coal cleaning process. In the most recent BCR study funded by the Department of Energy, twenty run-of-mine coals will be subjected to conventional cleaning processes as well as to more extensive non-conventional processes to evaluate the effect of such cleaning on fugitive elements--those elements which might be released to the surroundings and cause environmental problems. Based on the initial results in cleaning the first few coals, coal cleaning represents a method for controlling potentially harmful constituents of coal such as arsenic, cadmium, lead, mercury, and selenium.

INTRODUCTION

In the early nineteen seventies, public concern was aroused by the appearance of a number of newspaper and magazine articles concerning mercury pollution. Although most of these dealt with mercury in natural waterways and its effect on aquatic life, a few suggested that the burning of fossil fuels might contribute significant amounts of mercury to the environment. At that time, a program was established by the coal industry through its research organization, Bituminous Coal Research, Inc., to investigate and evaluate such potential problems concerning mercury and other trace elements in coal and coal-related materials. An additional motive for the program was the increasing concern with trace elements on the part of the government regulatory agencies and the need to temper any future judgments against the coal industry with the presentation of factual information.

The first order of business in the new BCR program was the development or adaptation of analytical procedures for the precise, accurate determination of trace elements in coal and coal-related materials. Some of this information developed on the program was described in two reports (Bituminous Coal Research, Inc., 1974 and 1975). Later, these analytical capabilities were tested and applied to solving potential coal industry problems in evaluating the effect of a rough coal-cleaning process on the distribution and removal of potentially harmful trace elements in coal (Ford, Care, and Bosshart, 1976). In that study, involving coal samples from only one step of an extensive cleaning process specifically designed for pyrite removal, some beneficiation with respect to trace elements was demonstrated even with only the initial rough cleaning.

Based on those promising results, a more extensive coal cleaning scheme was outlined, specifically designed to evaluate the effect of such cleaning on trace or fugitive elements, those constituents of coal which have the potential to be released and cause environmental problems. This paper describes initial progress on the fugitive element studies. The work was originally funded jointly by the U.S. Bureau of Mines, by the U.S. Energy Research and Development Administration (ERDA), and by Bituminous Coal Research, Inc. Funding is presently continuing with ERDA which is now part of the U.S. Department of Energy.

Background and Justification

Coal has been found to contain nearly every naturally-occurring element. With the exceptions of carbon, hydrogen, oxygen, nitrogen, and sulfur, which are the principal constituents of coal, as well as iron, aluminum, silicon, and alkaline earth metals in the ash, most elements are present in minor or trace amounts.

During coal mining, preparation, and utilization, these elements may be released to the environment. Even though these fugitive elements are normally present at extremely low levels, it may not be possible to ignore them as some are known to be harmful to plant and animal life at relatively low concentrations. The problem may, in fact, be compounded due to the large coal tonnage consumed in electric power generation and the anticipated consumption for coal conversion.

Trace elements, specifically mercury, cadmium, lead, arsenic, and selenium, have been pointed to with increasing frequency over the past several years as potential environmental pollutants. One means of controlling trace-element emissions is to remove these trace constituents prior to combustion. Those trace elements associated with the ash might be removed during the coal preparation process. A preliminary study conducted by Bituminous Coal Research search, Inc., demonstrated that coal cleaning is a possible technology for controlling many of these potentially harmful constituents of coal which might be released during combustion. Based on the results of the study, more extensive coal cleaning was recommended to determine which steps in the coal-cleaning process are effective in removing fugitive elements, both the trace elements as well as the more prevalent constituents such as sulfur.

The need to better understand the fate of fugitive elements during the coal mining, preparation, and combustion processes is imperative; however, to date, few systematic studies of this nature have been undertaken. This project is an initial step in that direction.

Objectives and Scope

The overall objectives of the project are: (a) to prepare a comprehensive state-of-the-art report on the effect of coal mining, preparation, transportation, and utilization on the trace elements found in coal; (b) to determine the effect of coal cleaning on fugitive elements; and (c) to provide a description of accurate analytical methods that can be used by coal industry and commercial laboratories for determining the concentration of selected trace elements in a variety of coals. The portion of the study described here involves only the effect of coal cleaning on fugitive elements; further, only the first few of twenty coals to be cleaned for the overall study will be discussed. The other objectives are being pursued but are in an intermediate stage of development.

The objectives of this portion of the study were approached as follows:

The effect of coal cleaning on fugitive elements was evaluated by exhaustively studying samples of run-of-mine (ROM) coal obtained from various geographical locations throughout the United States. All ROM samples were subjected to controlled coal cleaning at the BCR laboratories. Each coal was crushed; the coarser fractions were subjected to heavy media separations, and the fine fraction was hydraulically classified. This cleaning is representative of that which presently exists in the industry.

Some of the coals were subjected to additional, more extensive, processing and evaluation. Representative samples of these were crushed, screened, and the resulting narrow particle size range fractions were hydraulically classified. This type of cleaning represents optimum coal cleaning attainable, although not necessarily possible, using presently available technology.

Each sample produced by the coal-cleaning task was characterized by general chemical and trace element analysis, as well as petrographic analyses where appropriate. Those fugitive elements chosen for study include the trace elements antimony, arsenic, beryllium, cadmium, chromium, copper, fluorine, lead, manganese, mercury, nickel, selenium, vanadium, and zinc, along with the more prevalent constituents such as sulfur.

EXPERIMENTAL PROCEDURE

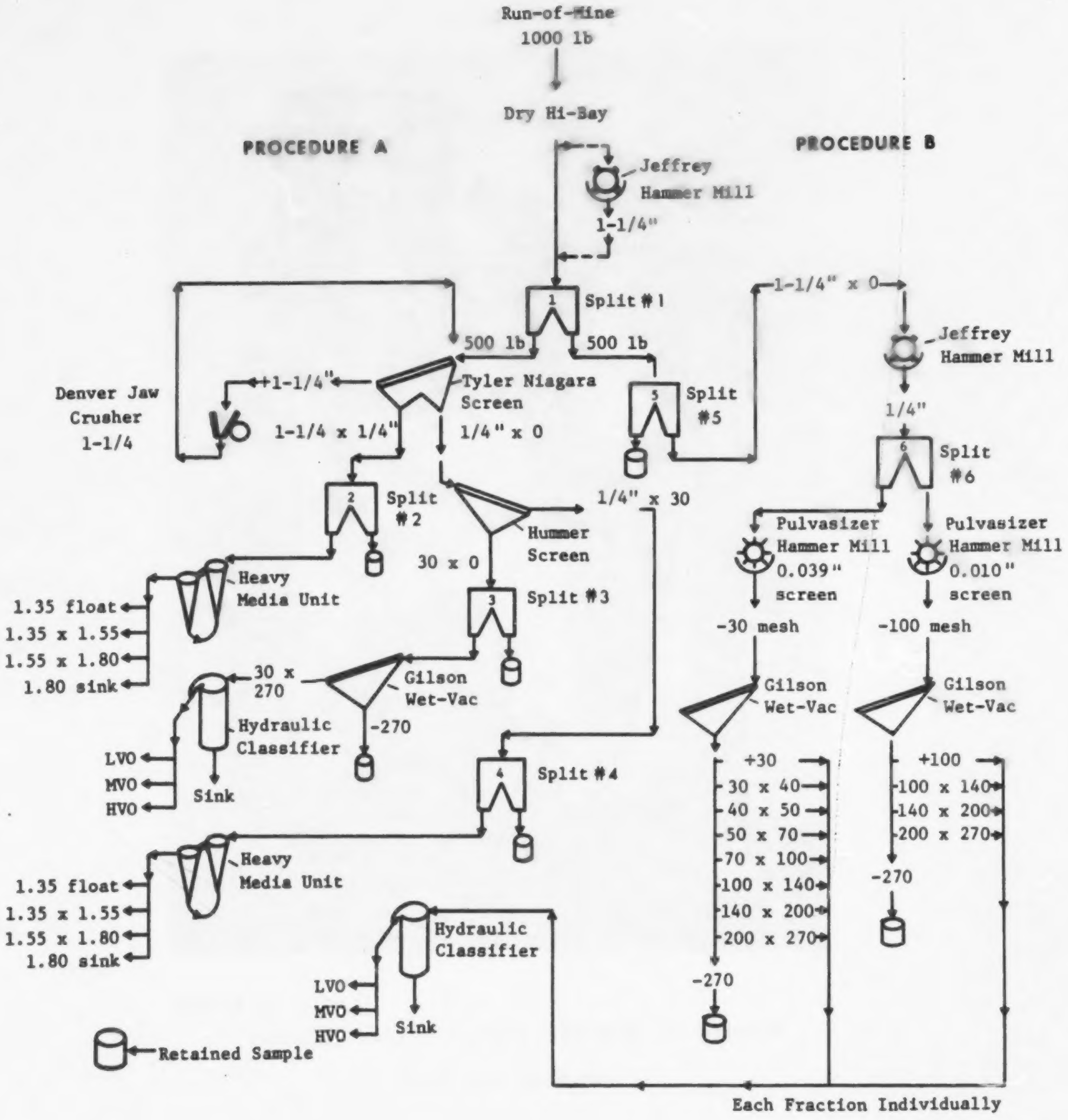
A major portion of the overall study is to determine the effect of coal cleaning on fugitive elements. This portion of the study can be divided into three segments--coal cleaning, coal analysis, including petrographic analysis, and data evaluation. The experimental approaches to each of the three segments are as follows:

Coal Cleaning

Approximately 450 kg (1,000 lb) of run-of-mine coal will be collected at each of twenty mines, placed in polyethylene bags to prevent trace-element contamination, and returned to BCR in 55-gallon drums. In each case, the coals will be representative of the seam or seams being mined at that site and have been selected on the basis of present and near-future importance in utilization.

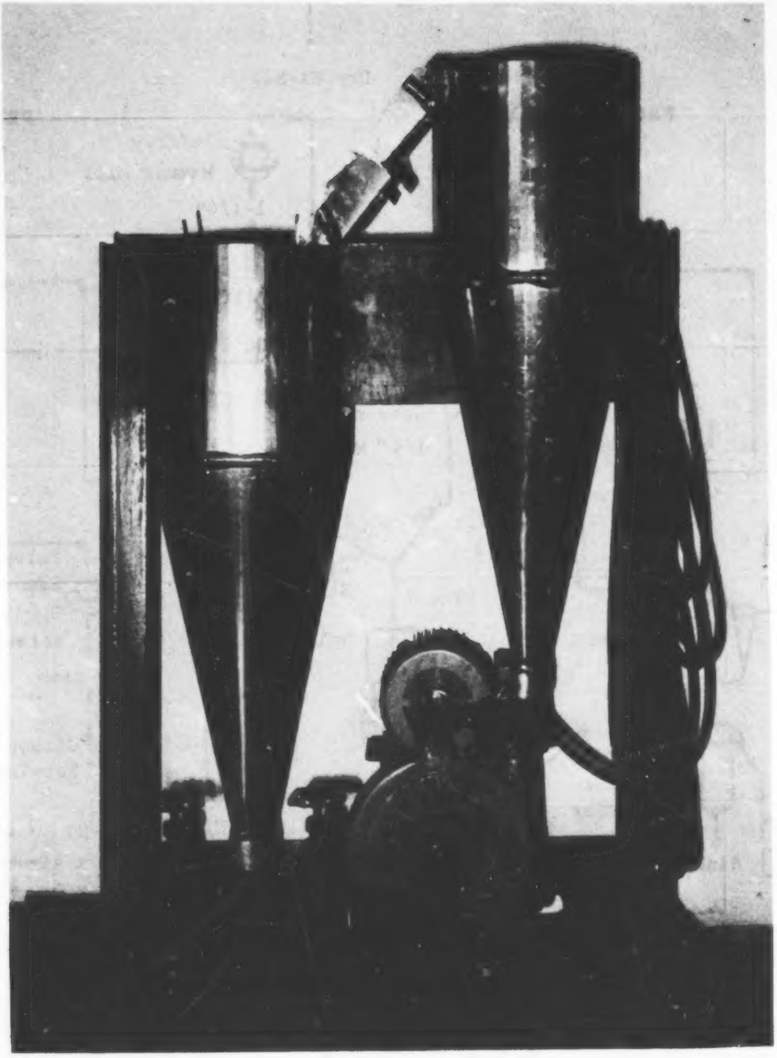
The two basic laboratory-controlled cleaning procedures utilized at BCR for this project are diagrammed in Figure 1, Preparation Flow Schematic. Procedure A, represented by the left portion of the schematic diagram, simulates coal cleaning techniques currently being utilized by the coal industry. This procedure involves basic crushing and screening to reduce the coal to three fractions: (a) 31.8 x 6.35 mm (1-1/4 x 1/4 inch), (b) 6.35 mm (1/4 inch) x 30 mesh, and (c) 30 mesh x 0. The 31.8 x 6.35-mm (1-1/4 x 1/4-inch) fractions and the 6.35-mm (1/4-inch) x 30-mesh fractions were then cleaned by heavy media gravity separations (Leonard and Mitchell, 1968) utilizing magnetite and the BCR double cone heavy media device pictured in Figure 2. Three separating gravities (1.35, 1.55, and 1.80) were used, producing four gravity fractions for each of the two coarse-size fractions.

The minus 30-mesh fraction was cleaned by utilizing the hydraulic classifier shown in Figure 3 after removal of the minus 270-mesh fines. Four fractions were produced from this cleaning: a low-velocity overflow, medium-velocity overflow, high velocity overflow, and a sink fraction.


Run-of-Mine
1000 lb
Dry Hi-Bay
PROCEDURE A
PROCEDURE B
Jeffrey Hammer Mill
1-1/4"
Split #1
500 lb
500 lb
Denver Jaw Crusher 1-1/4
+1-1/4"
Tyler Niagara Screen
1-1/4 x 1/4"
1/4" x 0
Split #5
1-1/4" x 0
Jeffrey Hammer Mill
1/4"
Split #6
Split #2
Hummer Screen
1/4" x 30
30 x 0
Heavy Media Unit
1.35 float
1.35 x 1.55
1.55 x 1.80
1.80 sink
Split #3
30 x 270
Gilson Wet-Vac
-270
Hydraulic Classifier
LVO
MVO
HVO
Sink
Split #4
Heavy Media Unit
1.35 float
1.35 x 1.55
1.55 x 1.80
1.80 sink
Hydraulic Classifier
LVO
MVO
HVO
Sink
Retained Sample
Pulvasizer Hammer Mill 0.039" screen
Pulvasizer Hammer Mill 0.010" screen
-30 mesh
-100 mesh
Gilson Wet-Vac
Gilson Wet-Vac
+30
30 x 40
40 x 50
50 x 70
70 x 100
100 x 140
140 x 200
200 x 270
-270
+100
100 x 140
140 x 200
200 x 270
-270
Each Fraction Individually

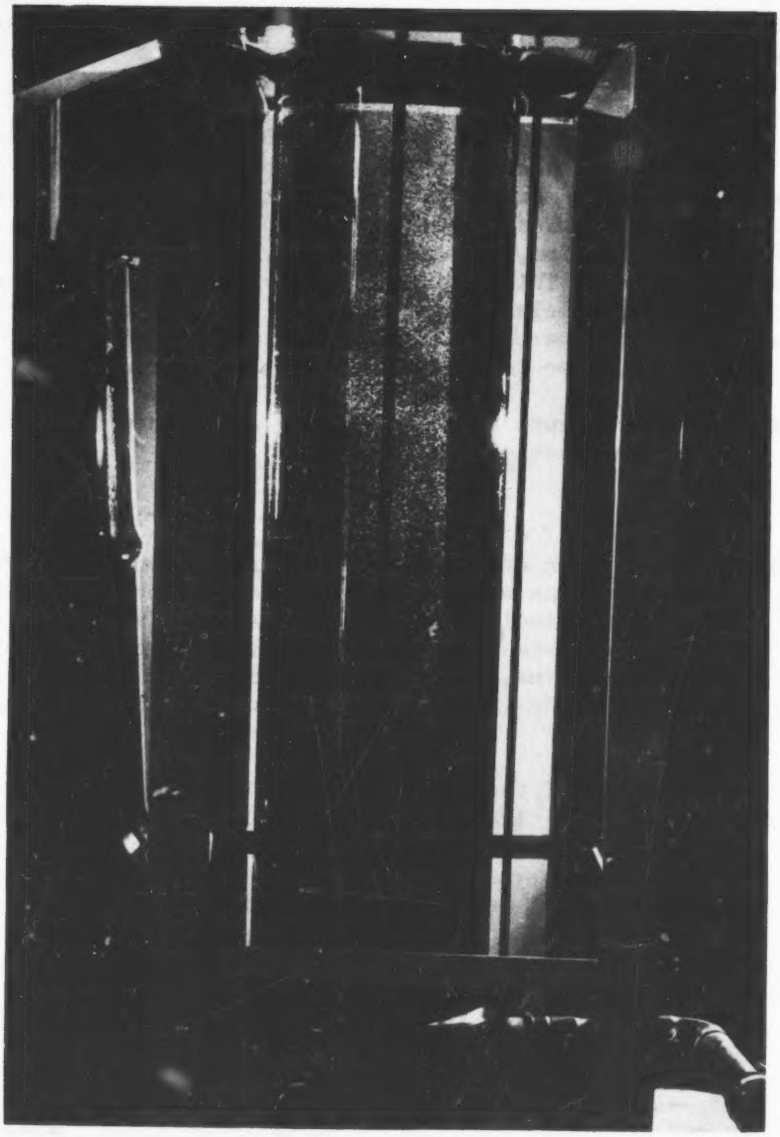
BCR 6082G1R1

Figure 1. Preparation Flow Schematic



6082P21

Figure 2. Double Cone Heavy Media Separatory Unit



6082P7

Figure 3. Hydraulic Classifier Column

Procedure B, represented by the right side of the schematic diagram, was utilized to simulate an "optimum" coal cleaning process. Basically, as was shown in Figure 1, the 31.8-mm (1-1/4-inch) x 0 ROM coal was reduced to a series of fine coal fractions using the screening apparatus shown in Figure 4. The fractions were sized from 30 mesh to minus 270 mesh and then cleaned in the hydraulic classifier. A schematic of the components of the hydraulic classifier system is shown in Figure 5. All but the minus 270-mesh fractions were subjected to hydraulic classification to produce an ultra-clean coal fraction, a clean coal fraction, a shale fraction, and a pyrite fraction for each of the size fractions. This "optimum" coal cleaning may not presently be feasible at commercial levels but was utilized in this project to identify trace elements present in fine clean coal, shale, and pyrite fractions, and to allow comparison with those found in larger-sized fractions.

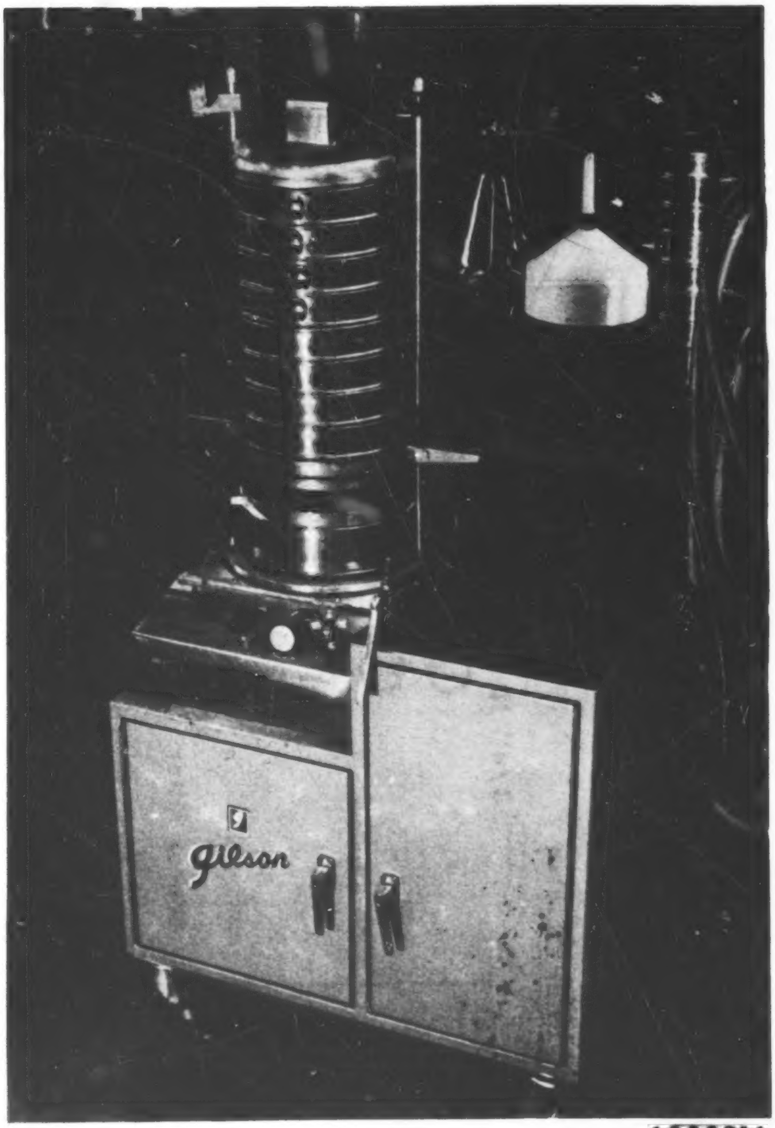
By utilizing both Procedure A and B, as many as 81 samples could be generated for trace element analysis.

Analytical Methods

For a thorough evaluation of the effect of cleaning on the coals, many general chemical determinations were made as well as the petrographic and trace determinations. These included proximate analysis (moisture, ash, volatile matter, and fixed carbon), ultimate analysis (carbon, hydrogen, nitrogen, total sulfur, chlorine, and oxygen by difference), calorific value, and sulfur forms. ASTM methods (ASTM, 1977) were used whenever possible and appropriate.

The major constituents of the coal ash--including silicon, aluminum, iron, magnesium, calcium, and titanium--were determined by optical emission spectrographic (OES) techniques. Sodium and potassium were determined by atomic absorption. Phosphorus was determined either by a wet-colorimetric procedure or by atomic emission techniques utilizing apparatus purchased for this project. The atomic emission spectrometer, a multi-element, direct-reading analytical tool with a plasma excitation source, provided initial accuracy checks for phosphorus and for those elements determined by atomic absorption.

A major portion of the BCR methods for determining trace constituents in coal is based on atomic absorption for the following reasons. First, and most important, proper use of this technique has been demonstrated to result in accurate, precise concentration values for trace constituents of coal when precautions are exercised in preparing the sample for these measurements. A second reason for selecting atomic absorption is its potential use for these types of analyses by coal industry and other laboratories. While the corresponding instrumentation is by no means inexpensive, it is certainly less expensive than other more exotic, equally accurate methods. Furthermore, a skilled technician can conduct the analyses once the procedures are in an advanced state of development.



6082P16

Figure 4. Wet-Vac Screening Apparatus

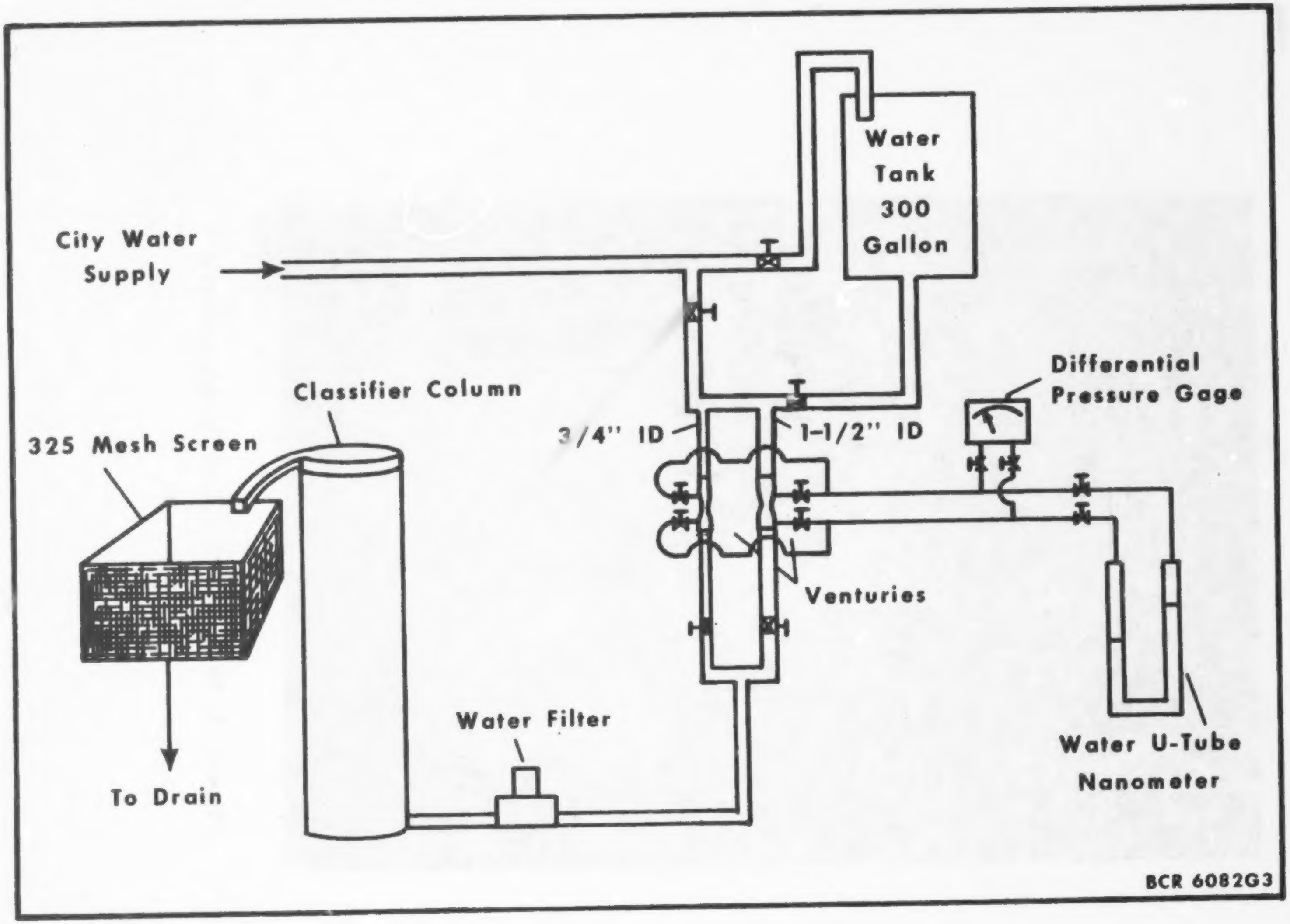

City Water Supply
Water Tank 300 Gallon
Classifier Column
325 Mesh Screen
3/4" ID
1-1/2" ID
Differential Pressure Gage
Venturies
Water Filter
To Drain
Water U-Tube Nanometer
BCR 6082G3

Figure 5. Hydraulic Classifier System Components

The following elements were determined by atomic absorption using a flame technique: arsenic, beryllium, chromium, copper, manganese, nickel, selenium, vanadium, zinc, antimony, sodium, and potassium. The cadmium and lead concentrations were too low in each of these coals to be detected by this flame technique; therefore, these elements were then determined by a flameless graphite furnace technique utilizing apparatus specifically purchased for this determination. The apparatus will also be useful for other low-concentration level determinations.

The solutions for flame and furnace atomic absorption as well as for atomic emission were prepared by dissolving the ash in teflon beakers with aqua regia/hydrofluoric acid (1:1) by boiling to dryness, adding nitric acid, and diluting to volume.

Arsenic, selenium, and antimony were determined by a unique procedure developed at BCR based on Eschka fusion, hydride generation, and atomic absorption using a hydrogen-argon flame. This procedure is presently being considered for round-robin testing by ASTM Committee D05 on Coal and Coke.

Mercury was determined by a combustion bomb method developed at BCR and by a double-gold amalgamation system constructed at BCR. Both techniques involve flameless atomic absorption and both are being considered for round-robin testing by ASTM Committee D05 on Coal and Coke. The first method has been tested with a great deal of success. Testing of the double-gold amalgamation system has been hampered by so few of the systems being available.

Fluorine was determined by a combustion bomb-selective ion electrode method. As the work progresses, the analytical techniques used, particularly for the trace-element determinations, including the most recent refinements, are being written, tested, and modified where needed. Later they will be incorporated into an analytical procedures manual for submission with the final report for this sponsored program.

The results of analyses are displayed on data sheets developed to show the results of each analytical determination for each of the various fractions obtained during the cleaning. One example of these is shown as Figure 6, which contains the ash content for all of the fractions obtained during cleaning of coal 1R, the first coal. From the data in this figure and from the other similar data sheets, obvious analytical errors can be immediately spotted. In this case, they could be observed readily as interruptions in the trend of low to high ash content from clean coal to refuse fractions. With the voluminous data being obtained during the course of this project, it would be easy to miss such simple errors caused, perhaps, by an incorrectly recorded sample number. In one case in a previous study, each fraction obtained had a higher concentration value than the feed from which it came. This was traced to a dilution error during analysis. Displaying the data as in Figure 6 minimizes the chances for these kinds of errors.

The analytical results for the individual samples are displayed as in Figure 7. The individual samples were also divided into groups for a clearer

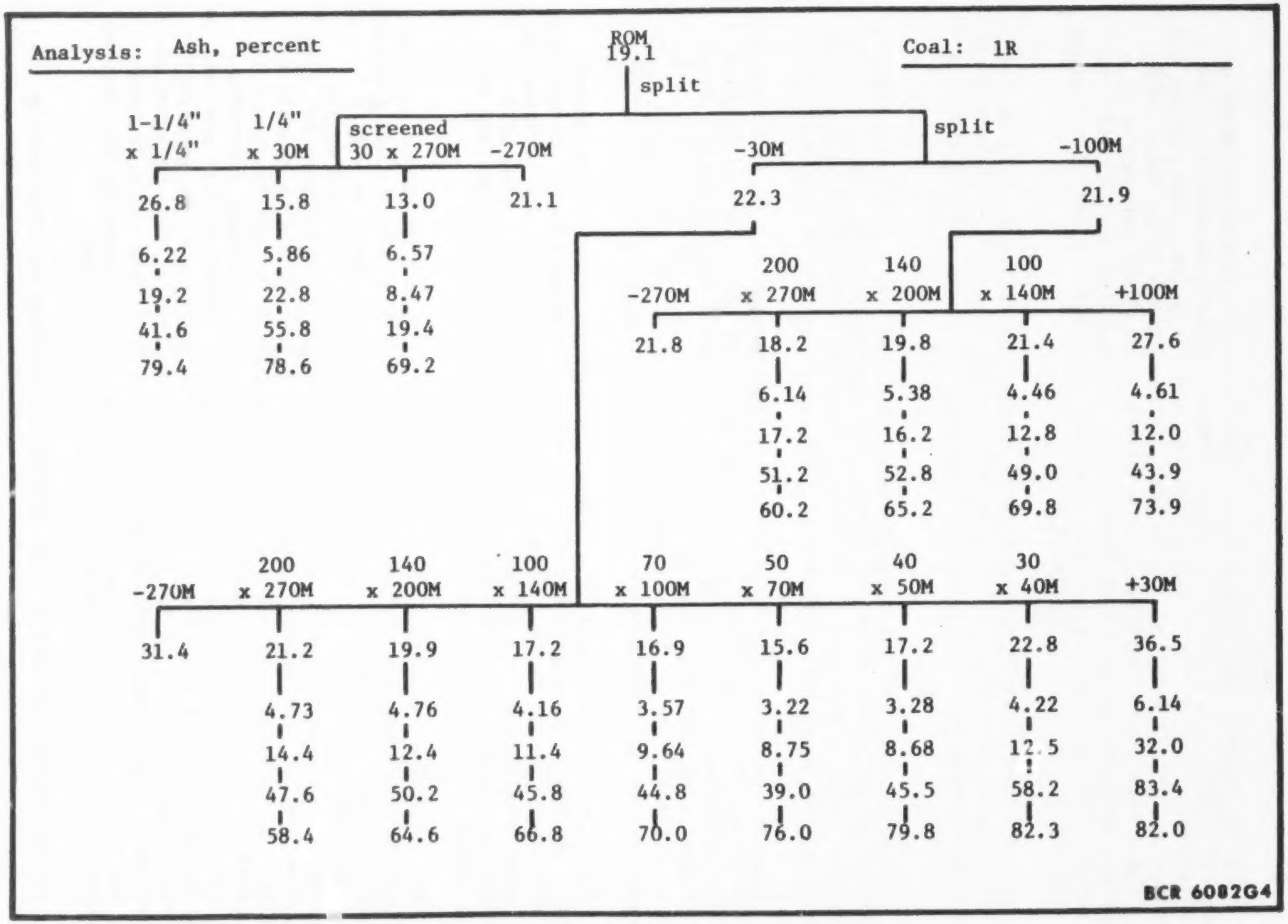

Analysis: Ash, percent
ROM
19.1
Coal: 1R
split
split
1-1/4" x 1/4"
1/4" x 30M
screened
30 x 270M
-270M
-30M
-100M
26.8
6.22
19.2
41.6
79.4
15.8
5.86
22.8
55.8
78.6
13.0
6.57
8.47
19.4
69.2
21.1
22.3
21.9
-270M
200 x 270M
140 x 200M
100 x 140M
+100M
21.8
18.2
6.14
17.2
51.2
60.2
19.8
5.38
16.2
52.8
65.2
21.4
4.46
12.8
49.0
69.8
27.6
4.61
12.0
43.9
73.9
-270M
200 x 270M
140 x 200M
100 x 140M
70 x 100M
50 x 70M
40 x 50M
30 x 40M
+30M
31.4
21.2
4.73
14.4
47.6
58.4
19.9
4.76
12.4
50.2
64.6
17.2
4.16
11.4
45.8
66.8
16.9
3.57
9.64
44.8
70.0
15.6
3.22
8.75
39.0
76.0
17.2
3.28
8.68
45.5
79.8
22.8
4.22
12.5
58.2
82.3
36.5
6.14
32.0
83.4
82.0
BCR 6082G4

Figure 6. Ash Content of Fractions of Cleaned Coal 1R

DATA SHEET, COAL PREPARATION-FUGITIVE ELEMENT STUDY

Analytical Lab No: 77-1071 Sample Code No: 1R-3M-2HC

PROXIMATE, %			ELEMENT, ppm		
Moisture		0.64	Arsenic	15.8	
Ash		8.47	Beryllium	1.34	
Volatile Matter		32.8	Cadmium	0.045	
Fixed Carbon		58.7	Chromium	16.3	
ULTIMATE, %			Copper	13.7	
Carbon		78.4	Fluorine	65.9	
Hydrogen		5.20	Lead	6.64	
Nitrogen		1.44	Manganese	21.1	
Sulfur		1.48	Mercury (ppb)	384	
Chlorine		0.20	Nickel	14.1	
Oxygen		4.81	Selenium	3.08	
SULFUR FORMS, %			Vanadium	30.4	
Sulfate		0.00	Zinc	19.9	
Pyritic		0.91	Antimony	0.94	
Organic		0.57			
MISCELLANEOUS					
Calorific Value Btu/lb		13,934			
MAJORS IN ASH, %					
SiO_2	45.4		Silicon	18,200	
Al_2O_3	25.7		Aluminum	11,700	
Fe_2O_3	16.0		Iron	9,620	
MgO	0.86		Magnesium	450	
CaO	5.82		Calcium	3,580	
TiO_2	1.38		Titanium	711	
MnO			Manganese		
Na_2O			Sodium	135	
K_2O			Potassium	1,490	
SO_3	1.52				
P_2O_5	0.56		Phosphorus	210	

BCR FORM P82

Figure 7. Data Sheet - Coal Preparation - Fugitive Elements Study

accounting of progress both in prepartion and in analyses. The relationship of these groups to the cleaning scheme is shown in Figure 8. Groups I, II, III, and IV involve cleaning Procedure A; the remainder concern Procedure B.

Details of each of the analytical procedures will be presented after the twenty coals have been cleaned and analyzed. At that time, one discrete section of the final report will describe the analytical procedures and their development in sufficient detail for use by coal industry and other laboratories involved in similar work.

Petrographic Methods

Petrographic analyses were employed to supplement the chemical tests designed to characterize coal separates evolved from the gravity cleaning and sizing techniques. These analyses involve the use of a light microscope to identify and measure coal constituents and included impurities which make up each separate. The following analyses were used to optically characterize each sample:

Coal composition: To identify and quantify the organic constituents characterizing the subject separate.

Pyrite mode of occurence: To determine the relative association of the pyrite impurity with the coal. (Free, surface, or encased)

Pyrite size: To measure and quantify the mean projected area diameter of the pyrite associated with the coal.

Results of the petrographic analyses will not be discussed in this brief paper.

Data Evaluation

Further evaluation of the data was aided by use of a computer. Mass balances were calculated and concentrations of the products were determined (a) based on the ultra-clean and clean coal fractions No. 1 and 2; (b) based on the ultra-clean and clean coal as well as the non-pyrite refuse fractions No. 1, 2, and 3; and (c) based on the middlings fractions No. 2 and 3 which might, in a real situation, be subjected to additional cleaning. A sample of the computer printout for the program written for the mass balance calculations is presented in Table 1. A differential value between the feed and composite is also calculated and displayed in order that judgments can be made on the entire operation including the cleaning and analyses.

Most of these calculated values might not be needed to evaluate each coal and each group; however, they will be available and are easier to obtain while the data are first being entered into the computer rather than having to reenter all of the data at some later time. For one coal, the material balances for 37 constituents and 18 different groups of feeds and separated fractions could result in a total of almost 700 sets of individual calculations, such as that displayed in Table 1, available for evaluation.

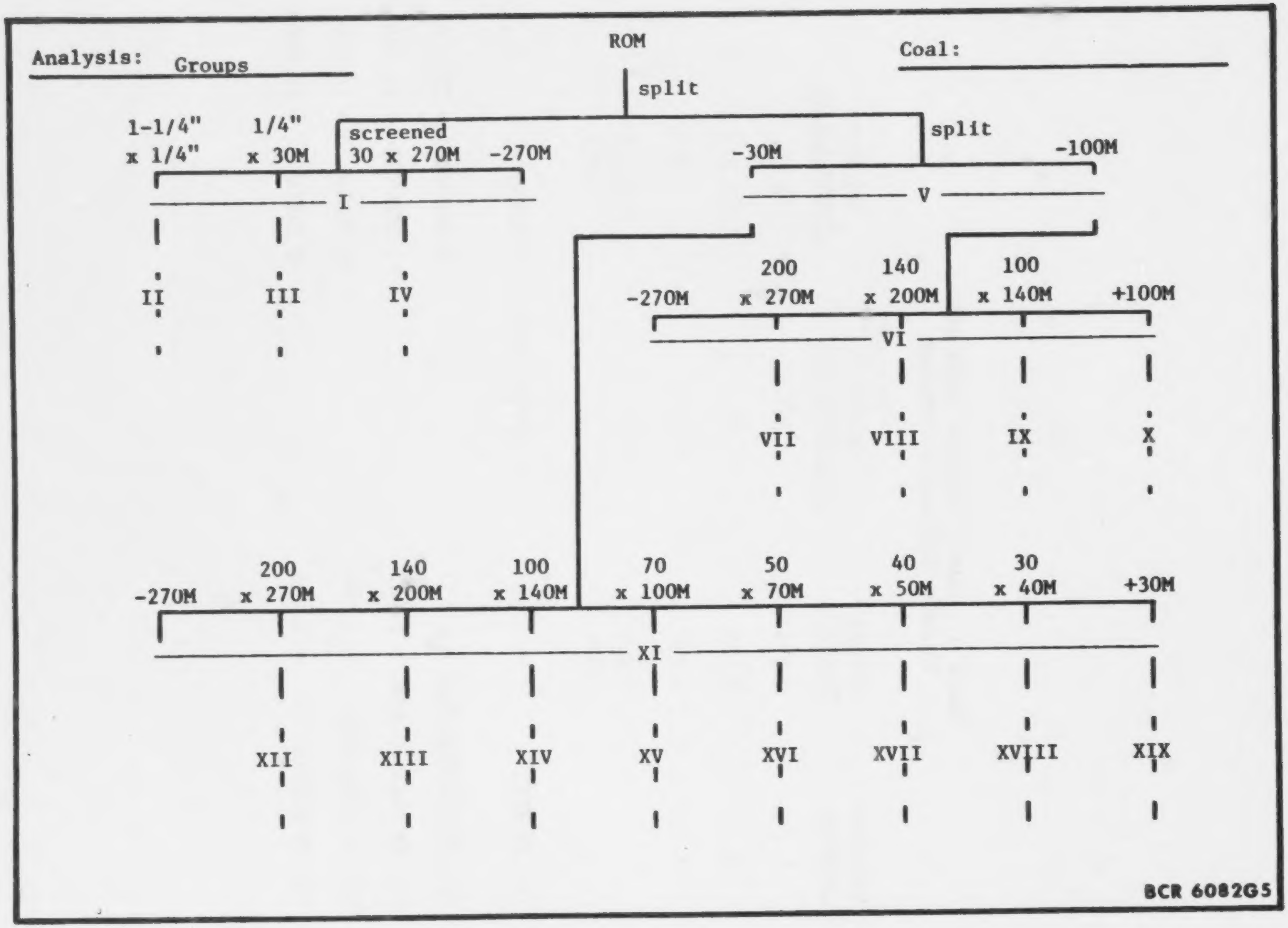

Analysis: Groups
ROM
Coal:
split
split
1-1/4" x 1/4"
1/4" x 30M
screened 30 x 270M
-270M
-30M
-100M
I
V
II
III
IV
-270M
200 x 270M
140 x 200M
100 x 140M
+100M
VI
VII
VIII
IX
X
-270M
200 x 270M
140 x 200M
100 x 140M
70 x 100M
50 x 70M
40 x 50M
30 x 40M
+30M
XI
XII
XIII
XIV
XV
XVI
XVII
XVIII
XIX
BCR 6082G5

Figure 8. Arrangement of Coal Fractions by Groups

TABLE 1. SAMPLE PRINTOUT FROM MASS BALANCE CALCULATION PROGRAM

```
FRACTION       WEIGHT           SULFUR                 WEIGHTED
 NUMBER       FRACTION       CONCENTRATION           CONCENTRATION

   1            0.574            1.09          =         0.626

   2            0.155            1.76          =         0.273

   3            0.055            3.80          =         0.209

   4            0.216            3.58          =         0.773
                1.000                                    1.881

[C] IN FEED           = 1.76          (COMP.-FEED) DIFFERENTIAL =  6.9%

[C] IN CLEANED COAL = 1.232                        % REMOVED    = 52.228

*[C] IN CLEANED COAL = 1.413                       *% REMOVED   = 41.116

[C] IN MIDDLINGS    = 2.294                        *% YIELD     = 78.400

[C] IN REFUSE       = 3.625                         % YIELD     = 72.900
```

Linear correlation coefficients and F-test ratios were also calculated to demonstrate the relationships between the percent removed of each constituent with the percent removed of every other constituent. This was done as an additional means of comparing the effectiveness of the fugitive element removal of the two coals. At this time, the percent removed was selected as the parameter to be evaluated. Later, when data for more coals are available, relationships between concentrations will be examined more thoroughly.

RESULTS AND DISCUSSION

Cleaning, analyses, and data evaluation of two coals are complete. One coal is a mixture of Upper and Lower Freeport seams and the other an Illinois No. 6 seam. Work on additional coals is in progress. The data were used in evaluating the effect of such cleaning on fugitive elements.

Coal Sampling

A list of the twenty coal seams to be sampled is shown in Table 2. Most of these have already been acquired and are available to the project.

Coal Cleaning

The first three coals were extensively cleaned using both Procedure A and Procedure B; the fourth coal involved only the shorter Procedure A. From the weight percent, ash, total sulfur, and calorific value data for the first two coals, the cleaning strategies employed were particularly effective and the separations needed to attain the objectives of the project were being achieved.

Washability studies were utilized primarily to determine how much coal could be produced at a given specific gravity and to define the ash and sulfur characteristics of the coal at that gravity. A washability study was made by testing coal samples at carefully controlled specific gravities, then analyzing the specific gravity fractions for ash and sulfur contents. A table was developed detailing the weight percentages and the ash and sulfur analysis for each fraction. The data were then mathematically combined into "cumulative float" and "cumulative sink" for both ash and sulfur and were utilized to develop "washability curves" which helped to characterize the coal. One example of the washability tables developed for this study, this one for the first coal, is presented in Table 3. The tables detail the separation gravities, the corresponding weight percentages, and the ash and sulfur analyses for each of the three size fractions.

The washability curves for the 31.8 x 6.35-mm (1-1/4 x 1/4-inch) fraction of coal 1R which was cleaned utilizing the heavy media unit are shown in Figure 9. Five curves are plotted on the chart: cumulative float ash (CFA), cumulative float sulfur (CFS), cumulative sink ash (CSA), cumulative sink sulfur (CSS), and the yield curve. As stated previously, these curves can be used to determine how much coal may be produced at a given specific

TABLE 2. COALS TO BE USED IN BCR FUGITIVE ELEMENT STUDY

Sample	Seam	Sample	Seam
1	Upper/Lower Freeport	11	Pocahontas No. 3
2	Illinois No. 6	12	Stockton
3	Rosebud	13	Sewell
4	Beulah-Zap	14	Mary Lee
5	Hannah No. 60	15	Kentucky No. 9
6	Adaville No. 1	16	Illinois No. 5
7	Castle Gate B	17	Imboden
8	Lower Kittaning	18	Upper Elkhorn
9	Pittsburgh	19	Pittsburgh
10	Meigs Creek	20	Lower Kittaning

TABLE 3. WASHABILITY ANALYSIS OF COAL 1R

Specific Gravity		Separates, percent			Cumulative Recovery, percent			Cumulative Rejects, percent		
Sink	Float	Yield	Ash	Sulfur	Yield	Ash	Sulfur	Yield	Ash	Sulfur
Group II 1-1/4 x 1/4 Inch Heavy Media - coarse										
	1.35	57.4	6.2	1.09	57.4	6.2	1.09	100.0	26.0	1.9
1.35	1.55	15.5	19.2	1.76	72.9	9.0	1.23	42.6	52.6	2.9
1.55	1.80	5.5	41.6	3.80	78.4	11.3	1.41	27.1	71.7	3.6
1.80		21.6	79.4	3.58	100.0	26.0	1.90	21.6	79.4	3.6
Group III 1/4 Inch x 30 Mesh Heavy Media - fine										
	1.35	79.6	5.9	1.06	79.6	5.9	1.06	100.0	15.7	2.24
1.35	1.55	6.8	22.8	2.64	86.4	7.2	1.19	20.4	54.2	6.86
1.55	1.80	5.2	55.8	5.67	91.6	10.0	1.44	13.6	69.9	8.96
1.80		8.4	78.6	11.0	100.0	15.7	2.24	8.4	78.6	11.0
Group IV 30 x 270 Mesh Hydraulic Classifier										
Average										
1.27		31.9	6.6	1.06	31.9	6.6	1.06	100.0	12.9	2.29
1.31		47.6	8.5	1.48	79.5	7.7	1.31	68.1	15.9	2.86
1.42		14.9	19.4	2.90	94.4	9.6	1.56	20.5	33.0	6.07
2.46		5.6	69.2	14.5	100.0	12.9	2.29	5.6	69.2	14.5

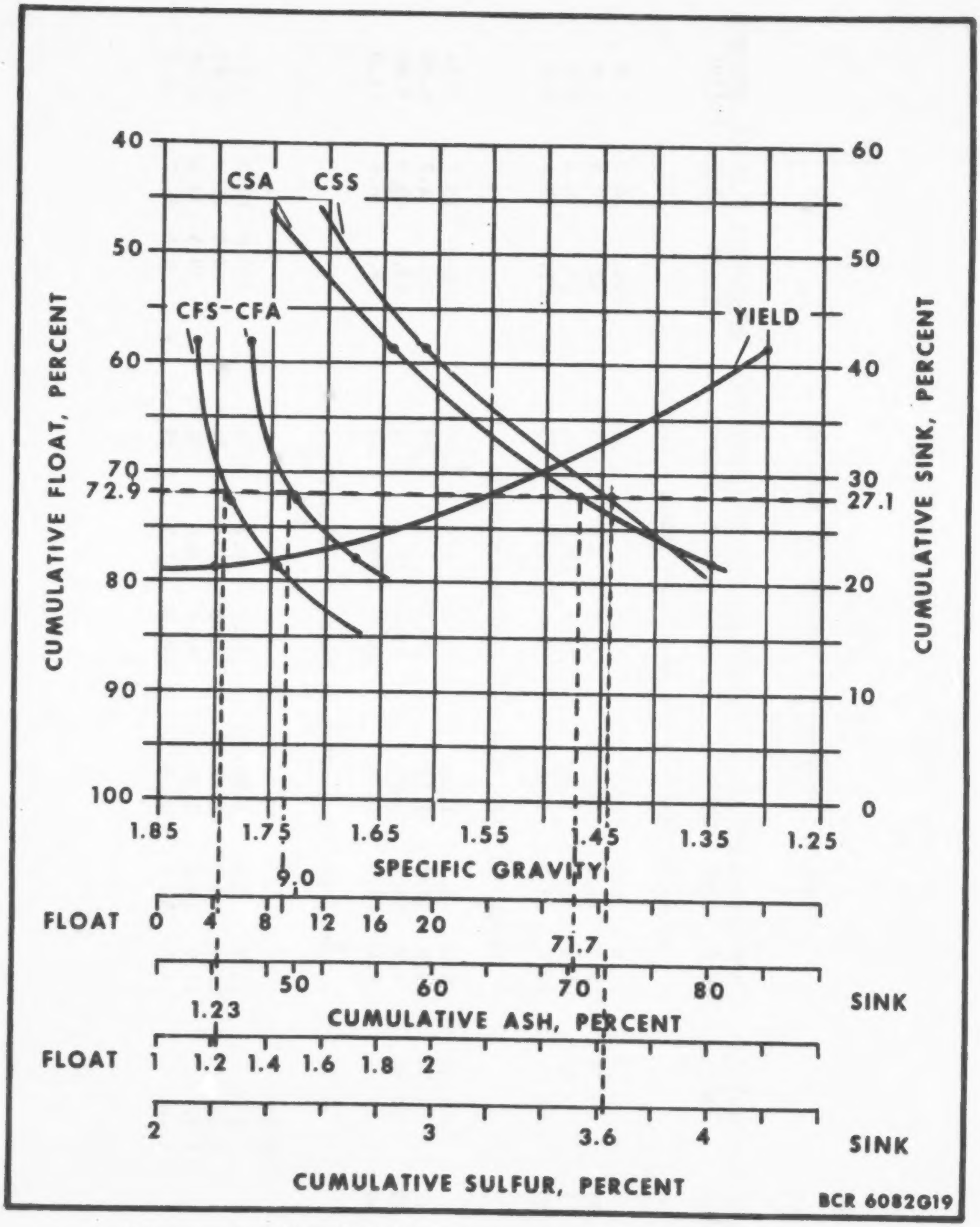


Figure 9. Washability Curves for the 1¼ × ¼ Inch Fractions of Coal 1R

gravity and to define the ash and sulfur characteristics of the coal at that gravity.

By referring to Figure 9, it can be seen that if a 1.55 specific gravity were chosen for the cleaning gravity of the 31.8 x 6.35-mm (1-1/4 x 1/4-inch) fraction of coal 1R, the following results would be expected: the yield in the float fraction would be 72.9 percent of the total feed coal, the float fraction would contain 9 percent ash and 1.23 percent sulfur, the sink fraction would contain 71.7 percent ash and 3.6 percent sulfur. It should also be noted that the slope of the cumulative float curves gives a quick estimate of the difficulty of cleaning a coal. The greater the slope, the more near-gravity material and the more difficult the coal is to clean.

By interpreting the data presented and by utilizing the washability curves, general statements can be made about the characteristics of the two coals and the response of the coals to cleaning.

For example, it can be inferred that coal 2R is more resistant to pulverization than 1R. Coal 2R contains a higher percentage of material in the coarse size fraction, 31.8 x 6.35-mm (1-1/4 x 1/4-inch), and a lower percentage in the fines, 30 x 270-mesh, than coal 1R. The higher percentage in the coarse screen fraction of coal 2R indicates that less degradation occurred during the screening, implying that coal 2R is harder than 1R.

When compared at a 1.45 specific gravity, the 6.35-mm (1/4-inch) x 30-mesh fraction showed the best ash reduction potential for both coals. The 31.8 x 6.35-mm (1-1/4 x 1/4-inch) fraction of coal 1R had the highest percentage ash reduction (72 percent), but the feed ash was much higher than in the 6.35-mm (1/4-inch) x 30-mesh fraction, which yielded a higher float ash even with the 72 percent reduction. The ash reduction potential at the 1.45 gravity was poor for both coals at the 30 x 270-mesh size range. From the washability curves, a lower specific gravity separation for the 30 x 270-mesh fractions would yield a better cleaning response.

Coal 1R showed better total sulfur reduction potentials than 2R for all size ranges at the 1.45 specific gravity. Coal 1R inherently has a lower sulfur content at the run-of-mine level and also proved, even for the 30 x 270-mesh fraction, to be easier to clean to an acceptable sulfur level.

The changes in the Btu levels between the raw coals and the coals washed at 1.45 gravity were not significant. Only the 31.8 x 6.35-mm (1-1/4 x 1/4-inch) fraction of coal 1R showed a reasonable increase, 22.9 percent. The fine fractions, 30 x 270-mesh, of both coals showed a large reduction in Btu's when cleaned at 1.45 gravity. Again, a specific gravity lower than 1.45 would show a better response for the fines of both coals.

Analytical Data

The concentration values for the first four run-of-mine coals for this study are presented in Table 4. Differences in concentrations for each of the four are apparent. For example, the average concentration for 14 of the trace elements for coal 1R is 27 ppm; for coal 2R, it is 25 ppm; for coal 3R, it is 15 ppm. For the lignite, coal 4R, the average concentration for the same 14 elements is only 8 ppm.

Thirty-eight constituents of samples of each of the first four cleaned coals, including the run-of-mine sample, were determined. Contamination of samples was a continuing problem throughout the study. Instances of mercury, chromium, copper, lead, nickel, and zinc contamination were identified and documented. These will be described thoroughly both in a forthcoming paper and in a report on analytical procedures. Contamination was held to a minimum by routinely analyzing reagent blanks and other material used on the project such as the magnetite used in the heavy media separations.

Every determination was done in duplicate. Lack of duplication of values immediately precipitated an additional determination. Whenever possible and as time allowed, more than one procedure was used for the trace element determinations as a check on the accuracy of the analytical values obtained.

Finally, as a continual check on the analytical procedures during the project, National Bureau of Standards (NBS) certified reference materials, SRM-1632 Coal and SRM-1633 Fly Ash, were analyzed along with each new run-of-mine coal and its cleaned fractions. One example of the type of agreement normally obtained between the determined values and the NBS certified values is presented in Table 5.

A more thorough description of the analytical procedures and results of precision and accuracy studies is programmed at the end of the presently funded portion of this program, when the twenty coals have been cleaned and analyzed and the effect of the cleaning on fugitive elements has been determined.

Mass Balance Calculations

The analytical data for each coal were used in calculating mass balances for the various individual cleaning schemes for each coal. The mass balances for each of the determined constituents were calculated: (a) to check the integrity of the cleaned fractions and the validity of the analytical data by comparing the summation of the materials in each fraction with the feed material, and (b) to evaluate the reduction or enrichment of each constituent as a result of the cleaning process.

For each constituent, the concentration determined in a particular separated fraction was multiplied by the weight fraction of the feed coal which reported to that zone. The weighted concentrations thus obtained were

TABLE 4. COMPARISON OF CONCENTRATIONS OF RUN-OF-MINE COALS 1R, 2R, 3R, AND 4R (dry coal basis)

	Coal 1R	Coal 2R	Coal 3R	Coal 4R
Ash, percent	22.3	16.0	15.8	11.0
Total Sulfur, percent	2.30	2.73	1.18	0.89
Chlorine, percent	0.12	0.33	0.01	0.07
Pyritic Sulfur, percent	1.78	2.01	1.02	0.73
Organic Sulfur, percent	0.46	0.50	0.14	0.10
Arsenic, ppm	40.2	11.0	8.54	10.4
Beryllium, ppm	1.84	1.10	0.87	0.70
Cadmium, ppm	0.08	0.47	0.12	0.06
Chromium, ppm	29.7	21.1	8.21	5.16
Copper, ppm	22.1	11.0	13.2	6.98
Fluorine, ppm	115	113	63.6	32.0
Lead, ppm	15.4	21.8	12.8	1.86
Manganese, ppm	50.0	36.8	65.2	33.4
Mercury, ppb	662	154	154	110
Nickel, ppm	20.9	18.4	4.98	4.60
Selenium, ppm	6.20	1.83	1.61	0.96
Vanadium, ppm	44.4	26.2	14.0	10.8
Zinc, ppm	35.5	91.8	12.8	3.48
Antimony, ppm	1.09	0.40	1.78	0.55
Sodium, ppm	448	1,230	248	6,630
Potassium, ppm	5,460	2,980	1,110	574
Silicon, ppm	57,800	37,900	39,800	14,500
Aluminum, ppm	30,800	17,700	20,200	6,470
Iron, ppm	21,100	19,100	8,560	7,840
Magnesium, ppm	1,360	870	3,150	4,060
Calcium, ppm	2,090	3,110	6,790	16,100
Titanium, ppm	1,670	1,010	1,090	370
Phosphorus, ppm	260	160	85	140
Calorific Value, Btu/lb	11,640	11,902	10,990	10,558

TABLE 5. COMPARISON OF TRACE ELEMENT CONCENTRATIONS IN SRM-1632 COAL WITH NBS CERTIFIED VALUES

(All values in ppm on a dry coal basis)

Element	Average ppm Determined	NBS Value, ppm
Antimony	3.47*	not certified
Arsenic	6.22	5.9 ± 0.6
Beryllium	1.63	1.5†
Cadmium	0.17	0.19 ± 0.03
Chromium	20.5	20.2 ± 0.5
Copper	17.7	18 ± 2
Lead	31.7	30 ± 9
Manganese	45.6	40 ± 3
Nickel	14.1	15 ± 1
Potassium	2,680*	not certified
Selenium	2.88	2.9 ± 0.3
Sodium	362*	not certified
Vanadium	36.4	35 ± 3
Zinc	41.6	37 ± 4

* In agreement with other published values.

† Informational value.

summed, and this resultant composite concentration value was compared with the concentration in the feed.

The differential between composite and feed was obtained from each mass balance calculation as follows:

$$\text{Differential} = \frac{\text{Composite Value} - \text{Feed Value}}{\text{Feed Value}} \times 100$$

These values, since they indicate the extent of agreement between feed and product constituents, can offer much insight into both the cleaning and the analytical study. Judgments are possible on the cleaning process based on the agreement of many of the constituents within any one cleaning operation. Poor agreement generally might indicate problems with the integrity of the samples obtained by cleaning; good agreement with the exception of one or two constituents, might indicate problems in the analytical determination of the constituents. A consistent positive or negative bias would indicate gain or loss of a constituent during cleaning or analysis, or analytical problems with certain of the fractions, perhaps the clean coal or (more likely) the refuse.

The average percent differentials for each of the first four coals are summarized in Table 6. The values presented in the table are the averages (absolute value) from as many as 18 values from the individual cleaning operations. Low values indicate good agreement between composite and feed. Obviously, there is a great deal of satisfaction with these values. For the most part, the agreement was better for coals 1R, 2R, and 3R than it was for coal 4R.

Some of the lack of agreement can be attributed to the low concentrations of trace constituents associated with this fourth coal. The concentrations in solution were often at or near the detection limits of the analytical methods. Additionally, slight contamination of trace constituents routinely experienced and tolerated in previous analyses exerted a greater influence on results at the low concentration levels. Such low concentration levels will probably be experienced with other coals for this project.

Effect of Cleaning on Distribution and Removal

The analytical data were used in evaluating the effect of cleaning the run-of-mine coals on fugitive element removal. An example of the type of data available, a summary of the percent of each constituent removed as a result of cleaning coal 1R, is presented in Table 7.

This calculation assumes the first two fractions as the cleaned coal and the last two as the refuse. The corresponding product recovery for each group is presented at the top of each column in this table. Most of the constituents which were concentrated, not removed, by the cleaning were not included in this table. For the most part, these were inherent parts of the

TABLE 6. COMPARISON OF COMPOSITE AND FEED VALUES,
AVERAGE PERCENT DIFFERENTIAL
COALS 1R, 2R, 3R, and 4R

	Coal 1R	Coal 2R	Coal 3R	Coal 4R
Ash	2	3	5	15
Volatile Matter	2	1	1	6
Fixed Carbon	1	1	1	5
Carbon	1	1	1	3
Hydrogen	2	3	3	5
Nitrogen	2	2	5	12
Total Sulfur	4	2	5	7
Chlorine	11	6	19	36
Pyritic Sulfur	5	3	7	9
Organic Sulfur	5	3	11	7
Calorific Value	1	1	1	3
Arsenic	15	8	11	17
Beryllium	4	3	5	11
Cadmium	14	21	9	23
Chromiun	3	8	7	16
Copper	14	17	8	11
Fluorine	9	7	6	22
Lead	14	14	9	8
Manganese	3	7	4	13
Mercury	13	61	18	14
Nickel	9	8	25	41
Selenium	6	15	7	36
Vanadium	5	5	3	6
Zinc	6	21	23	39
Antimony	8	12	11	19
Sodium	10	11	10	19
Potassium	8	4	4	31
Silicon	4	4	4	31
Aluminum	4	4	3	20
Iron	5	5	9	12
Magnesium	7	4	11	12
Calcium	7	7	12	8
Titanium	3	4	5	14
Phosphorus	6	11	4	20
Average	6	9	8	16

TABLE 7. PERCENT REMOVED BY CLEANING,* COAL 1R

Constituent	GROUP															
	II	III	IV	XII	XIII	XIV	XV	XVI	XVII	XVIII	XIX	VII	VIII	IX	X	Av.
Product Recovery, percent	73	86	80	71	76	79	80	83	81	76	69	82	82	75	63	77
Ash	75	60	52	73	69	67	70	66	70	73	71	52	55	71	81	67
S_T	52	54	54	78	71	65	66	60	62	66	76	68	63	72	82	66
Cl	8	4	15	14	11	11	7	5	6	8	8	8	7	10	13	9
S_{pyr}	65	69	66	89	83	79	82	78	80	81	86	80	78	85	91	79
S_{org}	10	6	15	18	14	13	12	7	8	8	10	11	10	13	26	12
As	82	79	71	92	88	88	91	86	89	88	93	87	86	93	97	87
Be	45	22	26	38	37	28	29	26	29	38	44	23	25	37	50	33
Cd	63	53	52	64	68	63	66	63	78	67	69	58	56	66	78	64
Cr	64	41	34	51	48	45	50	46	51	56	60	35	39	55	65	49
Cu	61	50	48	66	63	57	61	55	58	64	64	49	48	64	76	59
F	61	42	42	55	56	53	56	43	51	55	61	30	31	49	67	50
Pb	71	62	59	71	70	72	73	73	75	81	65	60	66	82	88	71
Mn	89	77	58	85	83	82	85	81	85	87	82	69	75	87	93	81
Hg	55	67	69	73	72	71	65	71	70	76	82	68	64	59	92	70
Ni	53	42	42	60	58	64	55	45	50	61	64	46	49	60	72	55
Se	44	65	67	82	78	73	75	74	72	79	83	74	72	80	88	74
V	63	36	31	47	39	41	42	39	44	55	58	30	32	52	66	45
Zn	74	58	45	71	66	61	66	62	65	71	65	51	51	67	78	63
Sb	29	33	28	36	42	30	35	22	32	28	52	28	29	41	60	35
Na	73	46	45	66	61	56	61	56	61	65	64	42	46	62	73	58
K	80	67	55	73	69	53	72	69	74	78	72	49	54	73	83	68
Si	77	61	51	72	68	67	69	68	71	74	71	49	54	71	80	67
Al	69	52	46	65	60	59	61	58	62	68	64	42	47	63	73	59
Fe	73	72	67	91	85	84	86	83	84	87	87	82	78	90	94	83
Mg	85	67	52	72	69	70	73	72	77	84	75	48	55	74	84	70
Ca	53	42	38	77	76	69	67	58	58	59	62	59	59	68	76	61
Ti	68	49	42	59	56	52	55	52	58	64	62	43	42	60	71	56
P	46	24	34	51	44	38	43	37	31	43	53	33	35	45	61	41
Average	60	50	47	63	61	58	60	56	59	63	64	49	50	62	74	58

*Cleaned Coal = Fractions 1 and 2

coal molecule. The exceptions were chlorine and organic sulfur. An initial observation of the data for these two seems to show a slight amount removed--9 and 12 percent, respectively. However, since the mean or average percent of the material reporting to the refuse (for disposal) was 23 percent (100 percent minus the average product recovery of 77 percent), the overall result was a slight concentration of these two in the cleaned coal over the amounts in the feed.

The averages by group and by constituent reflect generally good removal of most of the constituents. Arsenic, iron, manganese, pyritic sulfur, selenium, lead, mercury, and magnesium were removed most effectively. Beryllium, antimony, phosphorus, and vanadium were removed least effectively. Chlorine and organic sulfur were actually concentrated slightly in the cleaned coal.

Similar data are available for each coal, assuming either the first two or first three fractions from the heavy media or the hydraulic classifier separations as the cleaned coal. The data are further summarized, in Table 8, by constituent for the first four coals. The values presented in Table 8 are the averages from the individual values for each of the cleaning operations, for example, from the last column on the right in Table 7.

The differences in the effectiveness of cleaning each coal can readily be seen from the data in Table 8. Most constituents were removed more effectively from coal 1R than from the other coals, but the product recovery was also the lowest for this coal. Cleaning was least effective with coal 4R, the lignite. However, the principal reason for this is simply that the concentrations of the impurities in this coal, as previously displayed in Table 4, were relatively low prior to cleaning.

It must be pointed out at the same time that the calorific value of this coal was also the lowest of the four. Perhaps the concept of a calculated expression relating the concentration of impurities per calorific value, similar to the "pounds of sulfur per million Btu's," is needed to compare the trace impurities in a wide variety of coals on an equal basis.

Differences in the relative rates of removal for each coal can also be observed from the data in Table 8. Cadmium and zinc were removed more effectively from coal 2R than from the others. They were also present in higher concentrations in this coal from the Illinois basin than in the other three.

Linear correlation coefficients and F-test ratios were calculated for the constituents to demonstrate the relationships between the percent removed of each constituent with the percent removed of every other constituent. The relationships were evaluated among "percent" of the constituents removed by group rather than among "concentration" of each constituent removed by coal. This was done simply because two coals are not a statistically significant representation to permit drawing any specific conclusions concerning coal in general and the effect of cleaning them on fugitive element removal. Concentration data will prove more meaningful later in the study when more coals are cleaned.

TABLE 8. COMPARISON OF EFFECTIVENESS OF CLEANING COALS 1R, 2R, 3R, AND 4R BY CONSTITUENT. AVERAGE PERCENT REMOVED FOR ALL GROUPS

	Coal 1R	Coal 2R	Coal 3R	Coal 4R
Product Recovery	77	87	87	88
Btu Recovery	91	97	92	94
Ash	67	48	41	23
Total Sulfur	66	46	56	46
Chlorine	9	8	16	14
Pyritic Sulfur	79	55	61	50
Organic Sulfur	12	9	16	14
Arsenic	87	53	70	50
Beryllium	33	20	21	14
Cadmium	64	77	34	15
Chromium	49	28	29	24
Copper	59	37	28	18
Fluorine	50	33	26	12
Lead	71	61	31	22
Manganese	81	65	20	33
Mercury	70	42	41	31
Nickel	55	25	27	19
Selenium	74	34	45	24
Vanadium	45	23	25	16
Zinc	63	71	30	22
Antimony	35	19	22	19
Sodium	58	25	28	9
Potassium	68	39	53	19
Silicon	67	43	43	32
Aluminum	59	42	37	19
Iron	83	65	76	51
Magnesium	70	42	13	12
Calcium	61	72	14	16
Titanium	56	34	33	27
Phosphorus	41	66	21	14
Average	58	42	34	24

The F-statistic was then utilized in evaluating the relationship at the selected confidence level. The relationships are summarized in Table 9 for the first two coals. Only those having the highest degree of correlation are listed. Even with the imperfect means of evaluating, the distinct differences between the two coals, particularly in response to cleaning, are again evident. The associations for 2R are essentially those described previously and proficiently for Illinois coals (Ruch, Gluskoter, and Shimp, 1974, Gluskoter, 1977). Many of these associations are quite different with coal 1R from the Appalachian region. Not only did the two coals respond quite differently to the cleaning as described, but also the relationships between the constituents as removed by the cleaning were different.

These studies with the first few coals, as well as previous limited rough cleaning studies at BCR with eight coals have confirmed that removal of some potentially harmful trace elements can be effected by coal cleaning. The studies thus far with the coals reported here revealed differing responses to the various cleaning processes. Generalizations concerning the effect of cleaning on fugitive elements are not possible at this time. Specific conclusions concerning elemental distributions are not possible either at this time. Some trends have already been noted and these will be reexamined when a statistically significant number of coals have been cleaned and analyzed. Studies with additional coals are planned and already under way.

The program is flexibly designed to add or delete constituents of coal by mutual agreement between the sponsor and BCR, as a result of new proposed legislation, or by some new evidence of environmental contamination. The extensive cleaning scheme will also be similarly modified when warranted by the initial results of the studies. Milestones in reporting for this study include a report in preparation on the state-of-the-art of fugitive element emissions as they relate to the coal industry, as well as two final reports, one describing the results of the studies, the other including a complete description of the analytical procedures used in the study.

TABLE 9. PERCENT REMOVAL RELATIONSHIPS, COAL 1R AND 2R

	Highest Degree of Correlation	
	Coal 1R	Coal 2R
P.R.*	Be, P	S_{org}
Ash	Cr, Cu, F, Mn, Zn, Na, Si, Al, Mg, Ti	K, Si, Al, Mg
S_T	S_{pyr}	S_{pyr}, Fe
Cl		S_{org}
S_{pyr}	S_T, As	S_T, Pb, Fe
S_{org}		P.R.*, Cl
As	S_{pyr}, Fe	
Be	P.R.*, Cr, V, Na, Ti, P	V, Ti
Cd		Zn
Cr	Ash, Be, V, Zn, Na, Si, Al, Mg, Ti	V
Cu	Ash, Zn, Na, Al, Ti	
F	Ash, Na, Al, Ti	K, Si, Mg
Pb		S_{pyr}, Fe
Mn	Ash, Zn, Si, Al	Ca
Hg		
Ni		
Se		
V	Be, Cr, Na, Al, Ti	Be, Cr, Ti
Zn	Ash, Cr, Cu, Mn, Na, K, Si, Al, Mg, Ti	Cd
Sb		
Na	Ash, Be, Cr, Cu, F, V, Zn, Si, Al, Mg, Ti	
K	Zn, Si, Al, Mg, Ti	Ash, Si, Mg, P
Si	Ash, Cr, Mn, Zn, Na, K, Al, Mg, Ti	Ash, F, K, Al, Mg
Al	Ash, Cr, Cu, F, Mn, V, Zn, Na, K, Si, Mg, Ti	Ash, Si
Fe	S_{pyr}, As	S_T, S_{pyr}, Pb
Mg	Ash, Cr, Mn, Zn, Na, K Si, Al, Ti	Ash, F, K, Si
Ca		Mn
Ti	Ash, Be, Cr, Cu, F, V, Zn, Na, K, Si, Al, Mg	Be, V
P	P.R.*, Be	K

*P.R. = Product Recovery

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PARTICLE SIZE DISTRIBUTION IN THE LIBERATION OF PYRITE IN COAL

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ABSTRACT

The potential for sulfur reduction by physical coal preparation is primarily dependent upon liberation of pyrite particles within the plant feed. Secondarily, the principles of separation, as applied in the various plant unit operations, determine the efficiency of rejection of the liberated pyrite. Unfortunately, the procedures currently utilized to establish the degree of pyrite liberation are crude, inadequate, and tedious. It follows that lack of data may preclude optimizing preparation plant design and operation preventing maximum pyrite rejection. It even appears that improper pyrite liberation and pre-separation processing may inhibit maximum rejection of liberated pyrite from a raw coal.

Pyrite liberation is basically dependent upon pyrite particle size, the nature of the pyrite particle occurrence, and the associations of the pyrite particles with other coal components. This paper describes studies designed to provide additional information on these fundamental questions. Laboratory procedures involving selective stage communication, particle sizing, gravity separations, and microscopic examinations are employed to better define the problems and seek pragmatic solutions.

Similar concerns apply to the liberation and separation of other coal components (mineral and phytogenic) of concern to coal preparation whether to minimize environmental problems or prepare feedstocks for coal conversion processes. The same relationships are operative in water mineralization from pyrite which creates coal mine drainage problems. The studies are viewed as fundamental to enhanced coal beneficiation and coal industry environmental approaches.

The occurrence of sulfur in coals as three forms (pyrite, inorganic sulfates, and organically-bound structures) explains the primary limitation to sulfur removal by physical coal beneficiation. Assuming none of the organic sulfur will be rejected, the organic sulfur concentration becomes the theoretical reduction limit. This limit is less than rigorous since not all of the pyritic or sulfate sulfur will be rejected, but some organic sulfur-containing coal components will accompany the refuse. The pragmatic question becomes: How much pyritic sulfur in a given coal can be rejected by physical beneficiation procedures?

The extent of pyritic sulfur rejection achievable is dependent upon: 1.) Pyrite particulate liberation, 2.) The development of an appropriate feed and its characteristics for the separational unit operation(s), and 3.) The characteristics of the separational process(es), which determine the efficiency of liberated pyrite rejection. Similar factors are usually evaluated to serve several coal processing objectives including product particle size and the rejection of other mineral matter in addition to pyrite. Consequently, the factors are typically not optimized solely to attain maximum pyrite rejection. Only the first of these factors - pyrite liberation - is considered in this discussion although the others are interrelated.

The Liberation of Pyrite

Pyrite liberation is not a YES or NO accomplishment. The extent of pyrite particle purity attainable varies from particles which are predominantly coal and/or mineral matter to those predominantly pyrite. The implications for rejection extends to the separational process and especially the density of separation. The more pyrite freed from lower density particles, the greater is the probability of lowering the sulfur content of the clean coal product. The concept that liberated "pyrite" may be readily separated from low mineral matter coal particles because of its high density can be misleading.

Pyrite liberation, as liberation of any mineral during processing, is achieved by particle size reduction and is controlled by the mode(s) of comminution. In many ores, there is a relatively narrow natural grain size distribution whose maximum frequency may range from 10 mm to roughly 40 microns. By reducing the total particle size of the feed to this natural prevalent grain size, the probability of freeing associated particles of different composition is maximized. Breakage across constant composition particles is not precluded. The cementitious material between adjacent particles usually is a significant parameter. This level of comminution must be approached (despite cost) to achieve acceptable quality and yield of concentrate following separation.

With the extreme heterogeneity of coals, the particle size of any given relatively homogeneous component may range from 30 mm to less than one micron, with a broad spectrum of component size distribution. Pyrite itself occurs in such variable modes while the desired organic coal components tend to have more consistent and smaller sizes (one to 50 microns) with the notable exception of vitrinite which may exist in massive formats of relatively high purity having much larger dimensions. Existing coal preparation procedures do not seek to liberate the organic components of coal, although this may become more critical as our coal conversion program matures. The shapes and associations of coal components are highly variable due to their combined phytogenic and geologic origin.

Consequently, coal beneficiation design for pyrite liberation must follow a philosophy divergent from ore processing in its comminution-liberation objectives based on economics, separational process requirements, dewatering considerations, and clean coal product handling.

Coal comminution, which begins with the mining system, must provide for as extensive a liberation as feasible, but need not be constrained by the minimum top particle size (3/8 to 4-inches) of the process feed. The friability of coals complicates the comminution control and produces levels of coal fines greater than desired but it also emphasizes the hardness variations of coal components which is critical in liberation considerations.

The potential for liberating pyrite particles in run-of-mine coals is variable and dependent upon: 1.) Range of pyrite particle size occurrence and their dissemination modes (from several inches to less than one micron). 2.) Coal component hardness varies from resilient exinites and pliable, fine grained clays to hard, brittle quartz and pyrite, 3.) The associations of coal components is highly heterogenous from isolated pyrite lenses (of millimeter thickness) to the localized single grain of pyrite (micron dimensions) completely encased in vitrinite. Some examples of this association variability are shown:

A surface textured-euhedral pyrite particle of millimeter dimension with intergrown coaly material. A dendritic pyrite particle of millimeter dimensions. Pyrite crystals of micron dimensions nucleated inside a plant fiber shown in transmitted and in reflected light. Framboidal clusters of about three micron diameter in a vitrinite. The highly textured, large surface area of a pyrite framboid as seen through the scanning electron microscope. Small opaque particles of pyrite encased in vitrinite as seen by thin section.

Inadequacy of Available Procedures to Establish Degree of Pyrite Liberation

The extent of liberation potential of any locked mineral particle is typically established by chemical analysis on a size-density designated set of fractions, often associated with comminution procedures. In contrast with metal ores where a high concentration of the desired component mineral is essential, in coals pyrite rejection is sought and seldom is there significant levels of high purity pyrite particles achieved. Coal-pyrite liberation evaluations seek measures of pyrite rejection into acceptably small refuse fractions whose pyrite concentrations may be no more than double those found in situ in the coal seam. In fact, carefully sized coal fractions which are fractionated by density (as at 2.80 gm/cc - where only iron sulfides and alkaline earth carbonates could be expected to sink) seldom exceed 80% FeS_2 purity. Extending beyond coal preparation, there have been studies made (Lovell, 1967) to concentrate pyrites from coal to be used for sulfuric acid manufacture and iron ores. This historical approach may be misleading in achieving either maximum pyrite rejection or desired coal recovery.

Approaches to Pyrite Liberation Evaluations

The conventional approach to express pyrite liberation from coal may be illustrated for the Clarion seam using data from Zeilinger and Deurbrouck, 1968. By procedural convention, the samples were crushed to 1 1/2-inches top size (feed 32-58% + 1 1/2-inches) and a portion further crushed to 3/8-inch top size. The minus 100 mesh (150 microns)(0.7 to 4.0 Wt. %) material was removed prior to particle density fractionation between 1.30 and 1.58. By summary from Table 1, when utilizing the most ideal conditions for sulfur rejection (1.30 gm/cc separation), there

Table 1

Pyrite Liberation Studies of the
Clarion Seams in Clarion County, PA*

	Upper Clarion Seams							
	1 1/2-inch x 100M				3/8-inch x 100M			
	%, S	Wt., %	S Recovery, %	S Rejection, %	%, S	Wt., %	S Recovery, %	S Rejection, %
Feed	3.48				3.63			
	5.90				5.42			
	4.03				4.23			
	4.74				5.24			
1.30F	1.71	43.9	21.6		1.66	48.5	22.2	
	1.68	29.3	8.3		1.64	32.3	9.8	
	2.06	63.5	32.5		1.94	66.1	30.3	
	1.94	52.4	21.4		1.87	58.8	21.0	
1.58F	2.43	84.4	58.9		2.25	83.2	51.6	
	2.58	74.3	32.5		2.41	77.1	34.3	
	2.64	91.0	59.6		2.41	90.3	51.4	
	2.84	88.4	53.0		2.51	86.5	41.4	
1.58S	9.16	15.6		41.1	10.43	16.8		48.3
	15.49	25.7		67.5	15.55	22.9		65.7
	18.07	9.0		40.4	21.09	9.7		48.4
	19.22	11.6		47.0	22.72	13.5		58.5

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* Zeilinger, J. and A. Deurbrouck. Preparation Characteristics of Coals From Clarion County, Pa. Report of Investigation 7174. U.S. Bureau of Mines. 1968.

was only slight reduction in sulfur recovery for two sample locations when contrasting the two stage 3/8-inch top size with the single stage 1 1/2-inch product. A sulfur recovery reduction of 2.2% from 32.5% and of 0.4% from 21.4%. The sulfur concentrations were lower, 0.04 and 0.12%, respectively, and yields higher. The liberation effect appears more pronounced when separating at 1.58 gm/cc where the sulfur rejection increased between 0.8 and 11.5%, although the sulfur concentrations in the clean coal are much higher under the latter condition. These data reflect the difficulty in liberating "pure" pyrite particles, but may be interpreted as indicating a coal with limited sulfur removal potential. Actually, this coal is subject to significant pyrite removal.

This type of data may be readily summarized to compare seam characteristics expressing liberation responses by crushing as shown in Zeilinger and Deurbrouck, 1968 - Table 36, and in Deurbrouck and Palowitch, 1966 - Table 1. Liberation by more extensive comminution to 14 mesh (1.2 mm) has subsequently been detailed by the same research group (Deurbrouck, 1972; Cavallaro, Johnston, and Deurbrouck, 1976), although this size is much smaller than currently processed industrially.

Another approach to express pyrite liberation was utilized at The Pennsylvania State University by Kestner, Confer, and Charmbury, 1962, in evaluating responses of different crusher types. The crushed product was screened and each size fraction separated at a density of 2.96 gm/cc to attain a measure of relatively pure pyrite particles liberated.

Since many pyrite particles extend to the sub-sieve size range other dimensional measurement techniques must be used. Microscopic particle size measurement, distributions and particle associations were reported from polished briquettes of minus 14 mesh coal samples by McCartney, O'Donnell, and Ergun, 1969. The samples studied included heavy liquid sink fractions. These workers concluded that "The probable efficiency of any process for pyrite removal from a given coal can be better estimated if the size distribution therein is known."

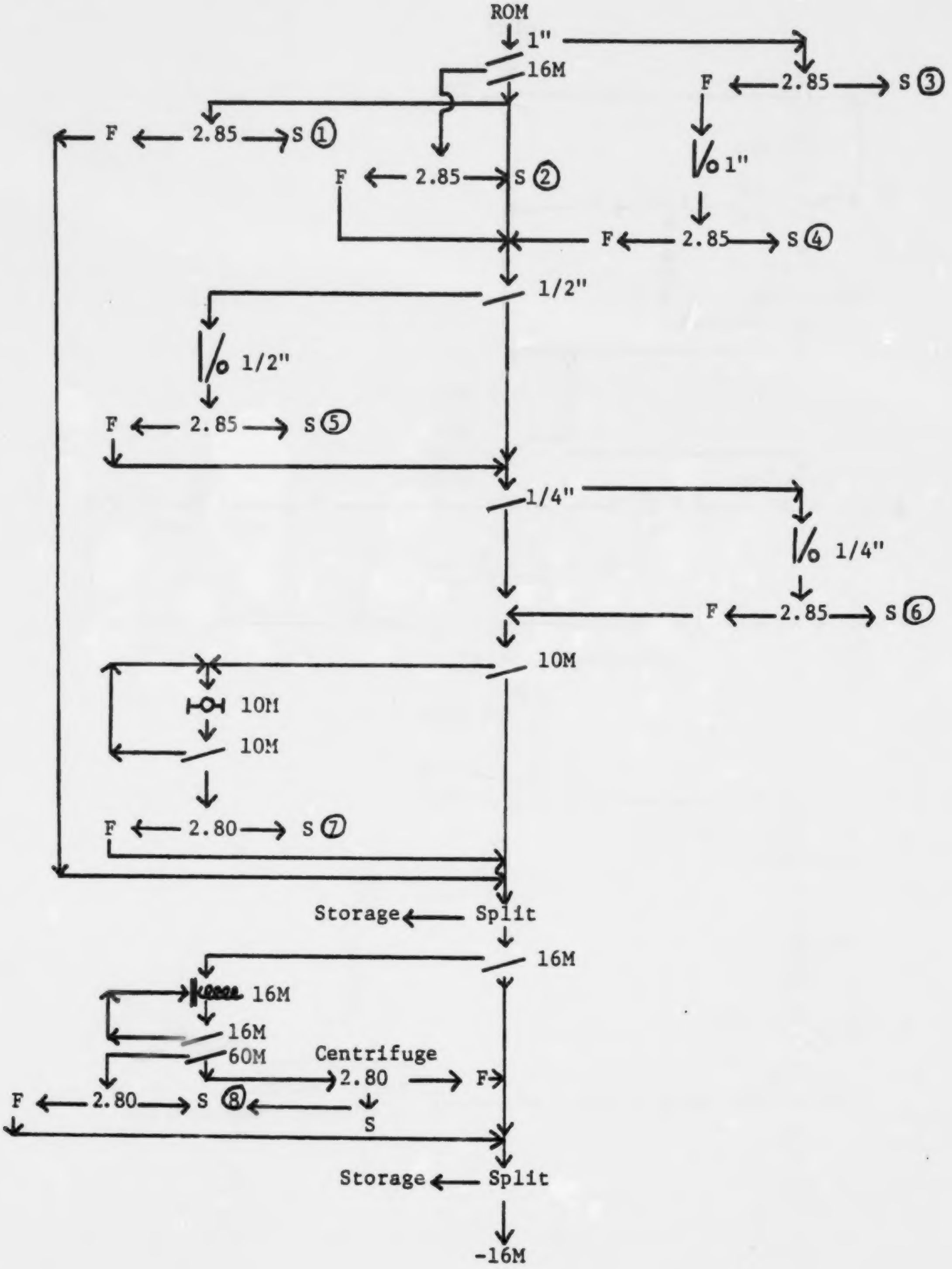
The use of coal particles mounted in polished epoxy resins for reflectance microscopy for pyrite, organic, and mineral coal components has been highly developed by Spackman, Davis, and Vastola, 1977, and Reyes-Navarro and Davis, 1976, at The Pennsylvania State University, including automated scanning and computer data handling. Pyrite is especially responsive to this technique due to its high reflectivity.

These microscopic techniques have been used to study coal pyrite occurrences in relationship to coal utilization and environmental impacts as coal mine drainage. Although microscopic measurements can be very effective in dealing with the sub-sieve pyrite particles, and especially with their component associations, they are more limited in dealing with coal preparation sulfur removal design studies since the particle sizes have been altered during sample preparation, the particles are less subject to chemical analyses, and the size distribution data are expressed on a volume percentage basis.

An Alternative Approach to Provide More Information on Pyrite Liberation

A procedure designed to be more helpful in pyrite liberation studies for physical coal beneficiation is being developed by Richardson and Lovell at The Pennsylvania State University. We also seek to further develop the concept as relates to the liberation and beneficiation of coal components other than pyrite as well as to environmental problems. The present format is tedious and complex, but simpler procedures for survey purposes are envisioned.

The coal sample was subject to the laboratory flowsheet shown in Figure 1. The data reported resulted from a 214 pound, hand-mined, channel of Lower Clarion Seam coal. The air dried, raw coal was screened at one-inch and 16 mesh (1.0 mm). The sized portions were fractionated with Certigrav at 2.85 gm/cc producing concentrates of essentially liberated pyrite with associated nonliberated coal and mineral components. These fractions give a reasonably direct measure of pyrite liberation as a result of the mining system employed. The fractions are sized by testing sieves and each size chemically analyzed for iron, sulfur, and other components. Should it be desired, a split of the 2.85 float sizes could be further separated at some lower density (as 1.60) to evaluate the pyrite distribution and concentration in such intermediate fractions. This approach



ROM
1"
16M
F
2.85
S ③
F
2.85
S ①
F
2.85
S ②
1"
F
2.85
S ④
1/2"
1/2"
F
2.85
S ⑤
1/4"
1/4"
F
2.85
S ⑥
10M
10M
10M
F
2.80
S ⑦
Storage
Split
16M
16M
16M
60M
Centrifuge
2.80
F
F
2.80
S ⑧
S
Storage
Split
-16M

Figure 1. Pyrite Liberation Flow Sheet.

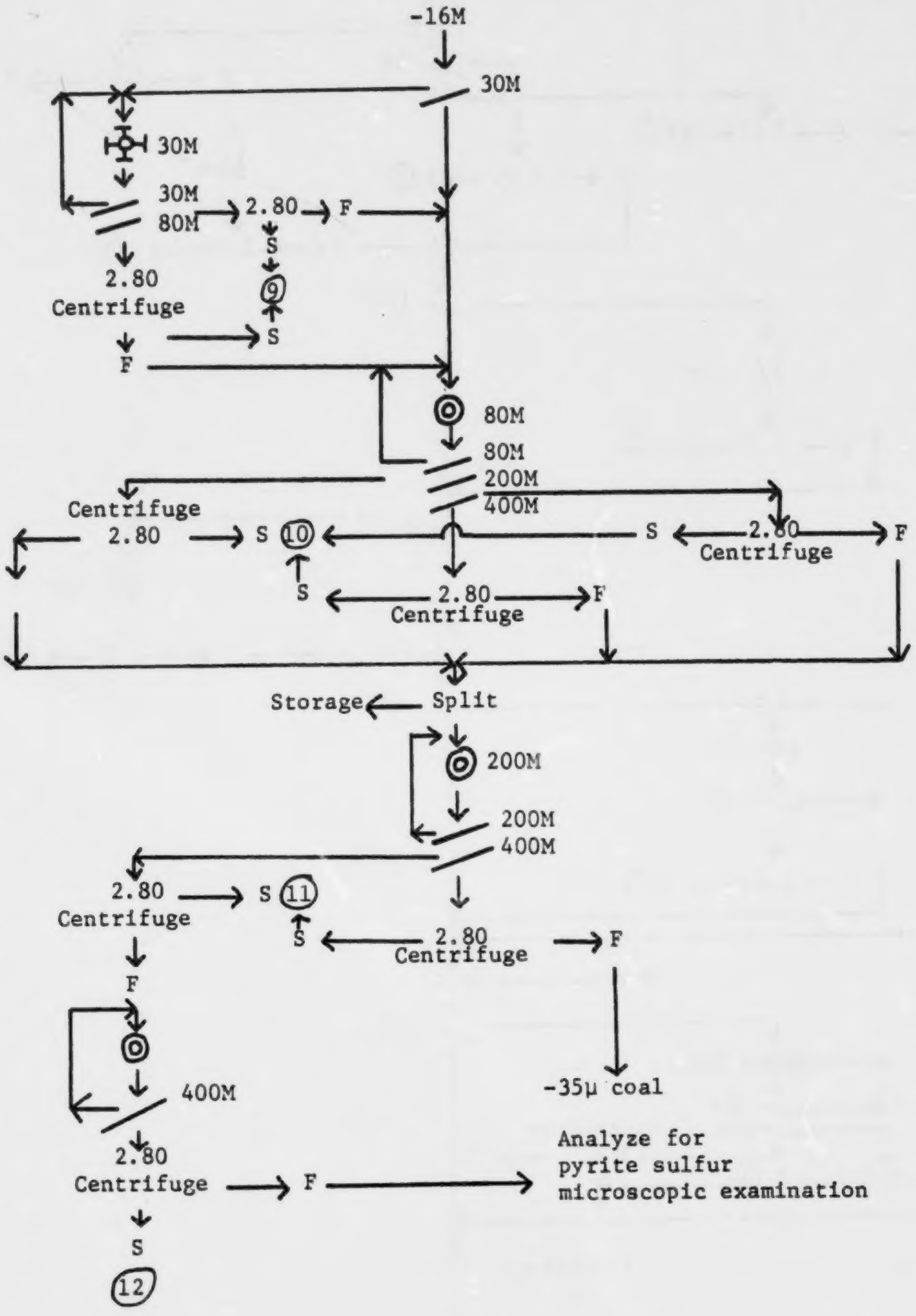

-16M
30M
30M
30M
80M
2.80
F
S
9
2.80
Centrifuge
S
F
80M
80M
200M
400M
Centrifuge
2.80
S
10
S
2.80
Centrifuge
F
S
2.80
Centrifuge
F
Storage
Split
200M
200M
400M
2.80
Centrifuge
S
11
S
2.80
Centrifuge
F
F
400M
2.80
Centrifuge
F
S
12
-35µ coal
Analyze for
pyrite sulfur
microscopic examination

Figure 1. Pyrite Liberation Flow Sheet (Continued)

eliminates unwanted, excessive breakage of the higher quality float particles.

The plus one-inch 2.85 float fraction was selectively and controllably crushed with the product separated at 2.85 gm/cc to give a pyrite liberation measure attainable in this size range (Sink Fraction 4). As detailed in Figure 1, individual stage crushing, sizing, and 2.85 sink fractions removal is developed at 1/2-inch, 1/4-inch, 10M, 16M, 30M, 80M, 200M, and 400M. After reaching the minus 10 mesh particle size, only aliquots of the residual sample were processed to reduce the time required.

The pyrite analyses of the several 2.85 sink fractions are shown in Table 2 with all having more than 72.0% pyrite, excepting Sample No. 12 (minus 35 micron) which did not respond adequately to the gravity separation.

The minus 35 micron 2.85 float material (representing 93.2% of the feed) contained 0.98% pyrite in contrast to 6.23% in the head sample. This represents a rejection of 84% of the pyrite at 2.85 gm/cc in only 6.8% of the feed! The pyrite rejection at the several stages of liberation studied is detailed in Table 3, with the sample numbers relatable to the flowsheet in Figure 1. Obviously, a separation at lower (and more conventional) densities would give substantially higher pyrite rejections at larger particle sizes - which were not considered for the purposes for which this study was designed.

Table 2
Pyrite Content in Clarion Seam
2.85 Sink Fractions

Sample No.[1]	FeS_2%[2]	FeS_2%-Range by Size
1	79.9	76.2-83.4
2	78.0	60.1-83.5
3	78.4	77.5-86.9
4	72.4	65.6-84.0
5	75.5	66.7-79.8
6	74.8	63.9-80.2
7	77.0	65.4-84.7
8	77.1	75.3-80.9
9	79.5	77.2-83.2
10	76.0	74.5-81.6
11	77.8	74.9-82.4
12	44.4	44.4
13	0.98	
Head (Measured)	6.23	
Head (Calculated)	6.02	

[1] Size and Chemical Analyses on each size.

[2] Chemical Analysis based on iron.

Table 3
Pyrite Particle Liberation by
Comminution Size in Clarion Seam Coal

Sample	% of Total Pyrite	Cumulative % of Total Pyrite
1	3.9	3.9
2	9.1	13.0
3	7.1	20.1
4	0.9	21.0
5	3.2	24.2
6	4.9	29.1
7	6.2	35.3
8	4.6	39.9
9	14.2	54.1
10	13.2	67.3
11	12.0	79.3
12	4.6	83.9
13	16.1	100.0

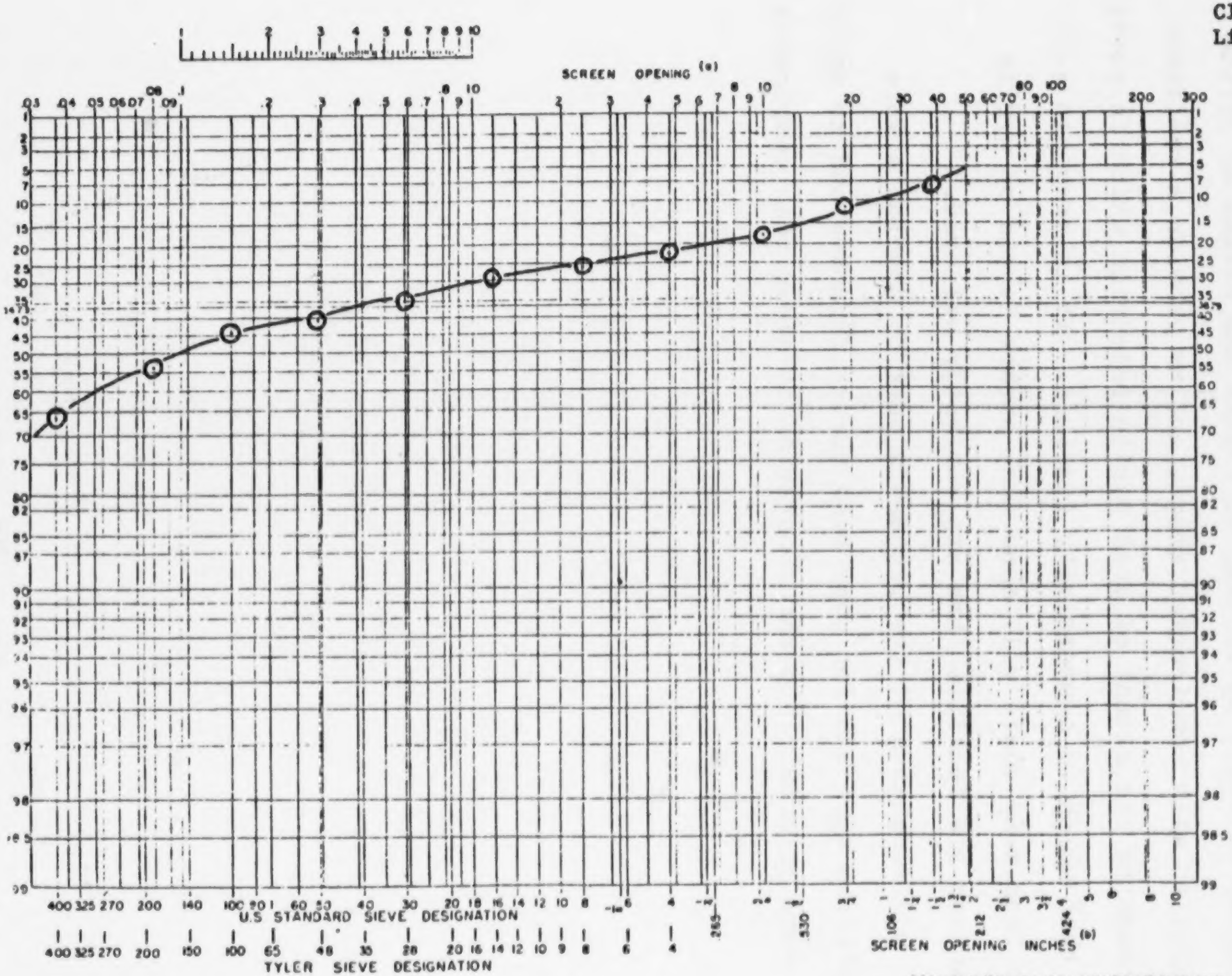
Photographs of the pyrite concentrate fractions above 1 mm show the occulsion of other components with the pyrite. Other visual observations show the same types of associations with smaller sized particles extending to the minus 35 micron fraction. These associations suggest explanations for the particulate behavior and poor performance in certain beneficiation operations - as froth flotation.

Another application, and perhaps the most significant data developed from this procedure, is a more realistic pyrite particle size distribution representing the pyrite as it existed in the coal seam. This compilation is shown in the Rosin-Rammler plot in Figure 2.

It is not suggested that some pyrite particles were not crushed, but the procedure does give a superior approximation on a weight basis to the existing distribution. Detailed review of the data permits broad application of the information for process design.

In summary, the reduction of sulfur in coals by physical beneficiation relates to the nature of pyrite liberation. This liberation is highly variable and relates to pyrite particle size occurrence-disseminations, coal component hardness variations, and the associations between the heterogenous coal components. Although various techniques exist, for expressing these relationships and utilizing them for coal beneficiation process design for sulfur reduction, none are fully adequate.

Clarion Seam
Liberated Pyrite



Sample No.________ Test No.________
Material________
Sieve Analysis by________
Date________
Plotted by________
Date________
Weight of gross sample________
Weight of test sample________

Sieve Analysis:

Point No.	Sieve Opening	Percentage	
		Retained	Cumulative

Characteristics

Point	Percentage	X, inches	Y, inches
A			
B			
Difference			

Distribution coefficient, n________
Absolute size constant ȳ________

(a) Any scale, if in millimeters, coincides with lower scale
(b) Square hole if used as continuation of fine series

GRAPHICAL FORM FOR REPRESENTING DISTRIBUTION OF SIZE OF BROKEN COAL

Figure 2

A concept of evaluating coal pyrite liberation is being developed and was illustrated for a Clarion seam coal. The procedure involves stage crushing, size separation, and removal of the relatively pure, liberated pyrite particles. These data may be evaluated to provide detailed pyrite particle size distribution directly by weight, to relate the extent of pyrite liberation with comminution stage, and to provide a realistic approach to the extent of coal pyrite rejection which is possible and that which is commercially feasible. It is proposed such data from many coals will show that higher levels of pyrite rejection are feasible than are currently believed.

Modifications of the procedure seek to develop a more simplified approach for coal seam survey purposes and to apply the same principles to the liberation of other coal components.

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GEOLOGIC CONTROLS ON MINERAL MATTER IN THE UPPER FREEPORT COAL BED

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ABSTRACT

Mineral matter in coal originates during various stages of coal formation. Many elements are known to be incorporated in plants and may be retained during peat formation and coalification. Major, minor, and trace elements may also enter swamps by sedimentological and geochemical processes where they may be retained during the peat-forming stage. After fixation in the peat, all elements, whether original or transported, may be mobilized in varying amounts and precipitated as authigenic minerals (e.g., carbonates, silicates, and sulfides) during and after peat accumulation. The various sedimentological and geochemical processes tend to concentrate suites of elements and minerals within coal zones.

Elemental, mineralogic, and maceral (i.e., vitrinite, exinite, and inertinite) associations form zones in the Upper Freeport coal of west-central Pennsylvania. Elements that tend to be concentrated in the top and/or bottom zones of the bed include As, Cd, Cl, Cu, Fe, Hg, Mn, Pb, S, Se, and Zn. Many trace elements such as B, Be, Cr, Cu, F, Li, Mn, Ni, Pb, Se, V, and Zn statistically correlate with Al, K, Mg, Na, and Si (elements that form the common clay minerals in the coal) and the ash. These trace elements (B, Be, Cr, etc.) probably entered the ancestral Upper Freeport swamp in association with clay particles as adsorbed and absorbed ions and/or they accumulated from degradation of plants. Some of these elements (e.g., B, Cr, F, Li, Ni, and V) may now be associated with the clay whereas others (Cu, Mn, Pb, Cd, Se, and Zn) were mobilized and precipitated as authigenic nonsilicate minerals. As, Ca, Fe, and Hg do not statistically correlate with ash content because their distribution was controlled by authigenic processes.

INTRODUCTION

Mineral matter refers to the inorganic constituents of coal (Rao and Gluskoter, 1973). Mineral phases and elements other than organically bound hydrogen, oxygen, nitrogen and sulfur are included in this definition. The variation of mineral-matter content of coal is governed by complex geologic, paleobotanical and geochemical processes. These processes control vertical and lateral variations in a given coal bed as well as the size and morphology of minerals. Vertical and lateral variation of mineral contents as well as size, morphology, and maceral association directly affect the preparation characteristics of the coal. For example, chemical analysis of bench-channel samples can demonstrate that pyrite is commonly concentrated in the top and bottom of coal beds; however, it does not provide information on pyrite size and form or indicate how the coal and associated pyrite will respond to coal preparation.

Fundamental to the problems of physical coal cleaning are the answers to questions such as, what is the mineral size, degree of crystallinity, and association with macerals, and do these factors vary systematically vertically and laterally in a given coal bed? The answers to these and related questions regarding mineral matter in coal can be obtained from geologic, geochemical and petrographic research. The data from such investigations coupled with float-sink testing can provide useful criteria for mine planning as well as for determining the preparation characteristics.

Origin of Mineral Matter in Coal

Mineral matter (i.e. contaminants) in coal can result from interrelated processes which are operable during the peat stage of coal formation prior to burial and from processes which are operable after burial. The preburial processes include (but are not limited to) 1) retention of mineral matter of plant origin in the peat; 2) deposition of detrital minerals; 3) sorption and/or precipitation of dissolved elements carried into the peat environment by water (either surface run off or brackish or marine waters from tides or storms); and 4) chemical and biological activity. Postburial processes include the formation of authigenic minerals in coal and on cleat surfaces from elements present in the peat and/or from elements derived from formation waters and surrounding sediments.

The pH of the peat-forming environment may be of critical importance in controlling not only the biological activity during peat formation but fixation and/or leaching of incipient coal mineral matter. Modern peat-forming environments have pH values ranging from 3.5 (e.g., the Okefenokee swamp of Georgia) to values greater than 7 (e.g., the Florida Everglades) (values measured by the writers). Peats which form in separate environments in which the waters are chemically dissimilar probably should also have dissimilar suites of elements; however, a great deal of research is needed to test this assumption. At low pH (pH 4), sulfate reducing bacteria are inactive whereas at higher pH values these bacteria are active resulting in the production of H_2S (Zajic, 1969, p. 8) if sulfate ions are available. This may lead to fixation of organic sulfur or iron sulfides depending upon the availability of sulfate and ferrous ions (Neavel, 1966).

After burial, many elements may be mobilized and precipated as authigenic minerals in the coal and on cleats. Common authigenic mineral types are silicates, carbonates, and sulfides. The mode of occurrence of these minerals is critical to coal preparation because removal is in part dependent upon mineral size and maceral association.

Objectives

The primary objective of this study is to evaluate the geologic controls on mineral matter content in coal with emphasis on pyritic sulfur in coal. A major part of this investigation is to determine relationships between vertical and lateral variation in mineral matter content of a coal bed reserve and how these variations effect physical preparation. The dedicated reserves of the Upper Freeport coal bed for the Homer City, Pa., generating station (jointly owned by New York State Electric and Gas and the Pennsylvania Electric Company) were selected for evaluation (fig. 1).

Methods of Study

The geologic controls on the mineral matter in the dedicated reserves are being evaluated by 1) detailed sampling and coal description of the two deep mines in the reserves (fig. 2); 2) analysis of core logs; 3) investigation of surface exposures of the Upper Freeport in the Homer City region; and 4) review previous work. At 21 locations (fig. 2), a total of 21 complete-channel and 75 bench-channel samples were collected from the two mines in the reserves. These samples are being analyzed for the following: 1) ultimate-proximate analysis and sulfur forms; 2) major, minor, and trace elements; 3) low-temperature ash mineralogy; 4) maceral composition; 5) pyrite forms, size and maceral association; 6) qualitative determination of accessory minerals by scanning electron microscope; and 7) ion-probe and electron-microprobe analysis of selected major, minor, and trace element mineral and maceral associations.

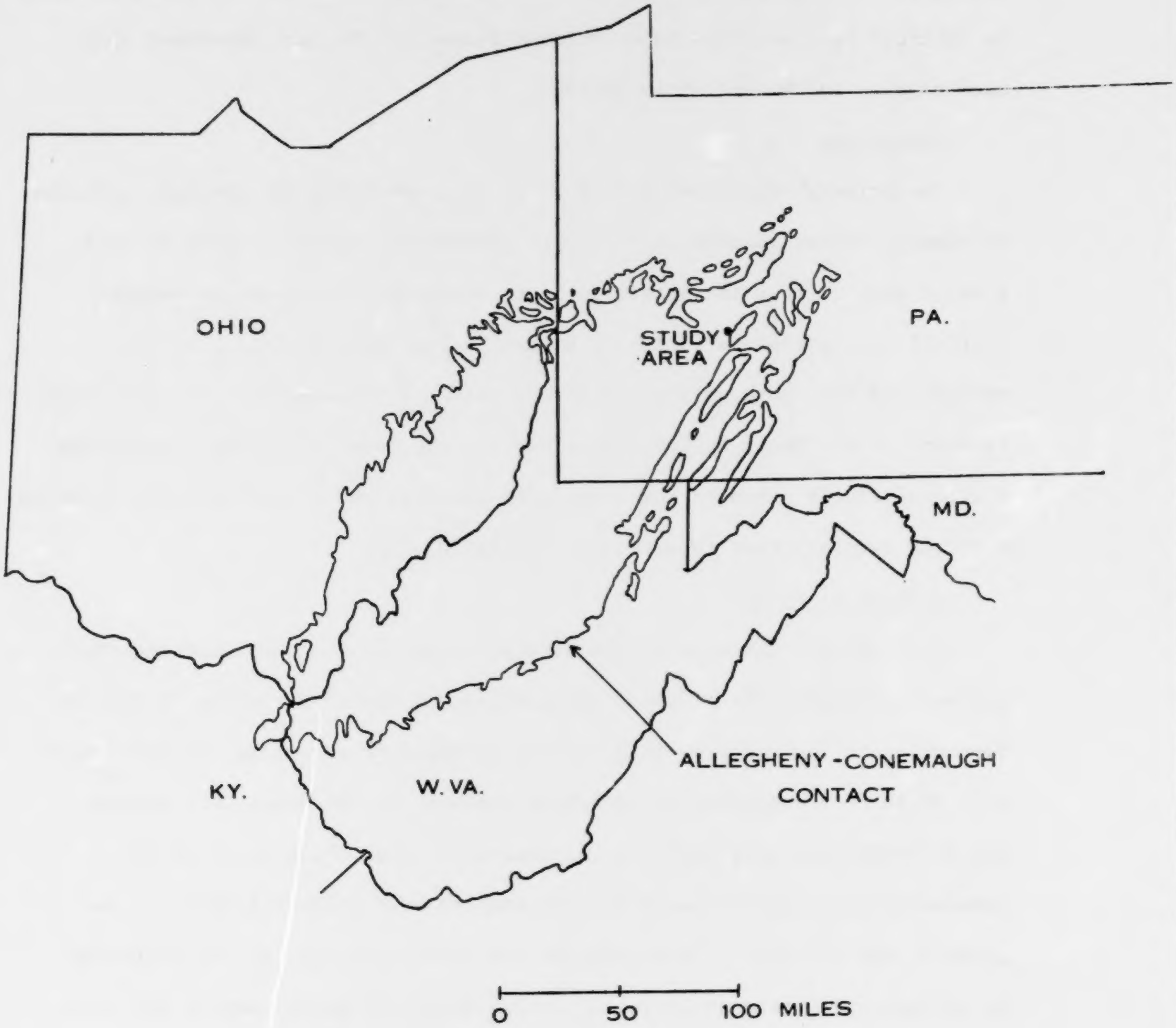
OHIO
PA.
STUDY AREA
MD.
KY.
W. VA.
ALLEGHENY - CONEMAUGH CONTACT
0
50
100 MILES

Figure 1. - Index Map of Homer City, Pa. Study Area and Allegeny - Conemaugh Contact.

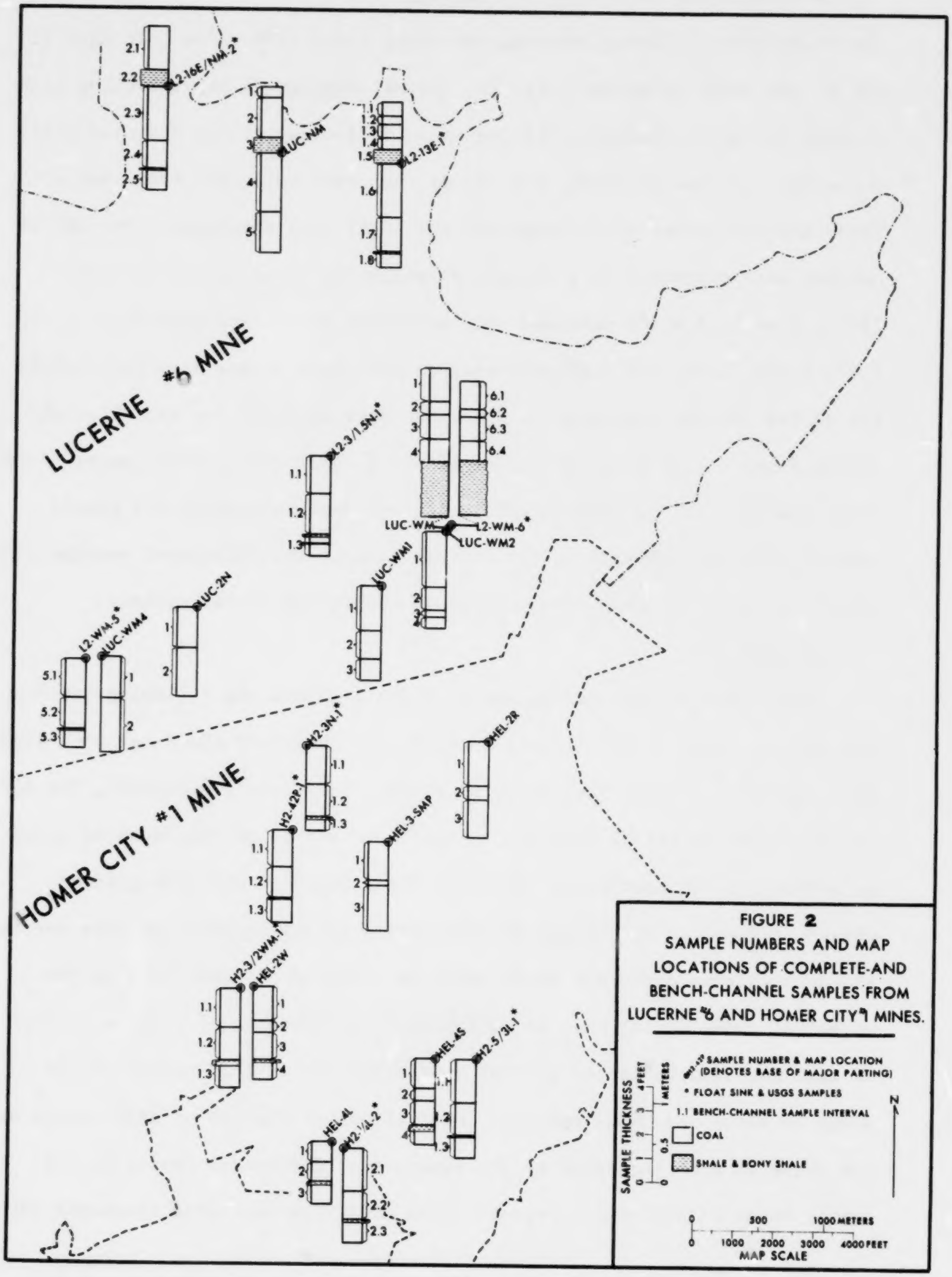
LUCERNE #6 MINE
HOMER CITY #1 MINE
L2-16E/NM-2*
LUC-NM
L2-13E-1*
L2-3/1.5N-1*
LUC-WM
L2-WM-6*
LUC-WM2
LUC-WM1
LUC-2N
L2-WM-5*
LUC-WM4
H2-3N-1*
HEL-2R
H2-42P-1*
HEL-3-SMP
H2-3/2WM-1*
HEL-2W
HEL-4S
H2-5/3L-1*
HEL-4L
H2-1/4L-2*
SAMPLE NUMBER & MAP LOCATION (DENOTES BASE OF MAJOR PARTING)
* FLOAT SINK & USGS SAMPLES
1.1 BENCH-CHANNEL SAMPLE INTERVAL
COAL
SHALE & BONY SHALE
SAMPLE THICKNESS
4 FEET
1 METERS
0.5
0
N
0
500
1000 METERS
1000
2000
3000
4000 FEET
MAP SCALE

FIGURE 2
SAMPLE NUMBERS AND MAP LOCATIONS OF COMPLETE-AND BENCH-CHANNEL SAMPLES FROM LUCERNE #6 AND HOMER CITY #1 MINES.

The relationship between the geology of the coal and its preparation characteristics is being investigated using float-sink tests. At each of ten of the above locations (fig. 2), channel samples of about 100 lbs each through the total thickness (48 inches to 83 inches) of the coal bed were collected. At one location, 100 lbs of coal were collected from each of three distinct zones which comprised the total coal thickness. The 100 lb samples were subjected to a 21-part size-gravity study (sized to 1/4", 1/4" x 8 mesh, 8 x 100 mesh and -100 mesh with float-sink testing at 1.275, 1.30, 1.325, 1.40, and 1.80 gravities on the three larger size fractions). All of the various size-gravity fractions were analyzed for ash, Btu, and sulfur forms. Five selected suites of the 21-part size-gravity samples are being analyzed in the same manner as in the complete-channel and bench-channel samples. Mineral matter distribution in the float-sink samples can then be related to the geologic controls on mineral matter content.

Results

From field investigations and core-log analysis the following has been determined. The ancestral Upper Freeport peat swamp of the Homer City study area formed on a broad flat alluvial plain. Immediately preceeding the formation of the ancestral peat environment, sedimentation consisted of mixed carbonate (the discontinuous limestone Upper Freeport and fine-grained clastic sediment. This suggests that waters moving through the area carried abundant calcium carbonate which may have affected pH conditions in the ancestral swamp during peat accumulation. The presence of calcite ($CaCO_3$) in coal macerals indicates partial neutralization of acid waters of the swamp by dissolved $CaCO_3$ species. Partial neutralization of acid waters of the swamp is also suggested by the presence of framboidal pyrite in the bottom bench of the coal. Certain forms of pyrite including framboids may result from bacterial activity during the preburial peat stage of coal formation (A. D. Cohen, personal commun.). Thus, the pH of the peat is important in biological activity as well as in the fixation of mineral matter during the peat stage of coal development.

The Upper Freeport coal bed of the Homer City study area consists of five distinct zones (fig. 3). These zones are genetically related to conditions that existed in the ancestral swamp during peat accumulation. The mineral matter variation of these zones is the result of the processes that were active during peat formation and of authigenic processes which were operable before and after burial. The C zone of the coal, in general, contains the highest ash content and the lowest total sulfur content.

Major-, minor-, and trace-element analysis of the bench-channel samples indicates definite genetic relationships for specific suites of minerals and associated elements. Forty-five elements show a positive statistical correlation with the ash content at the 95% confidence level (table 1). The data are indicative of a common source for the elements which make up the coal ash (excluding pyrite and $CaCO_3$). Pyritic sulfur does not correlate with the ash but correlates positively with arsenic and mercury (table 2). Elements that positively correlate with calcium (reported as CaO) are shown in table 3. The correlations indicate separate genetic relationships for $CaCO_3$, pyrite, and the ash correlative elements.

Preliminary statistical analysis indicates that there is a positive correlation between ash content and the sum of fusinite plus semifusinte (correlation coefficient = 0.73). The content of the inertinite group macerals as well as the ash is greatest in the C zone.

Preliminary analysis of pyrite forms and size of the bench-channel samples show three major distinctive types of pyrite occurrences. Zone B tends to contain massive replacement pyrite (some of which is arsenic

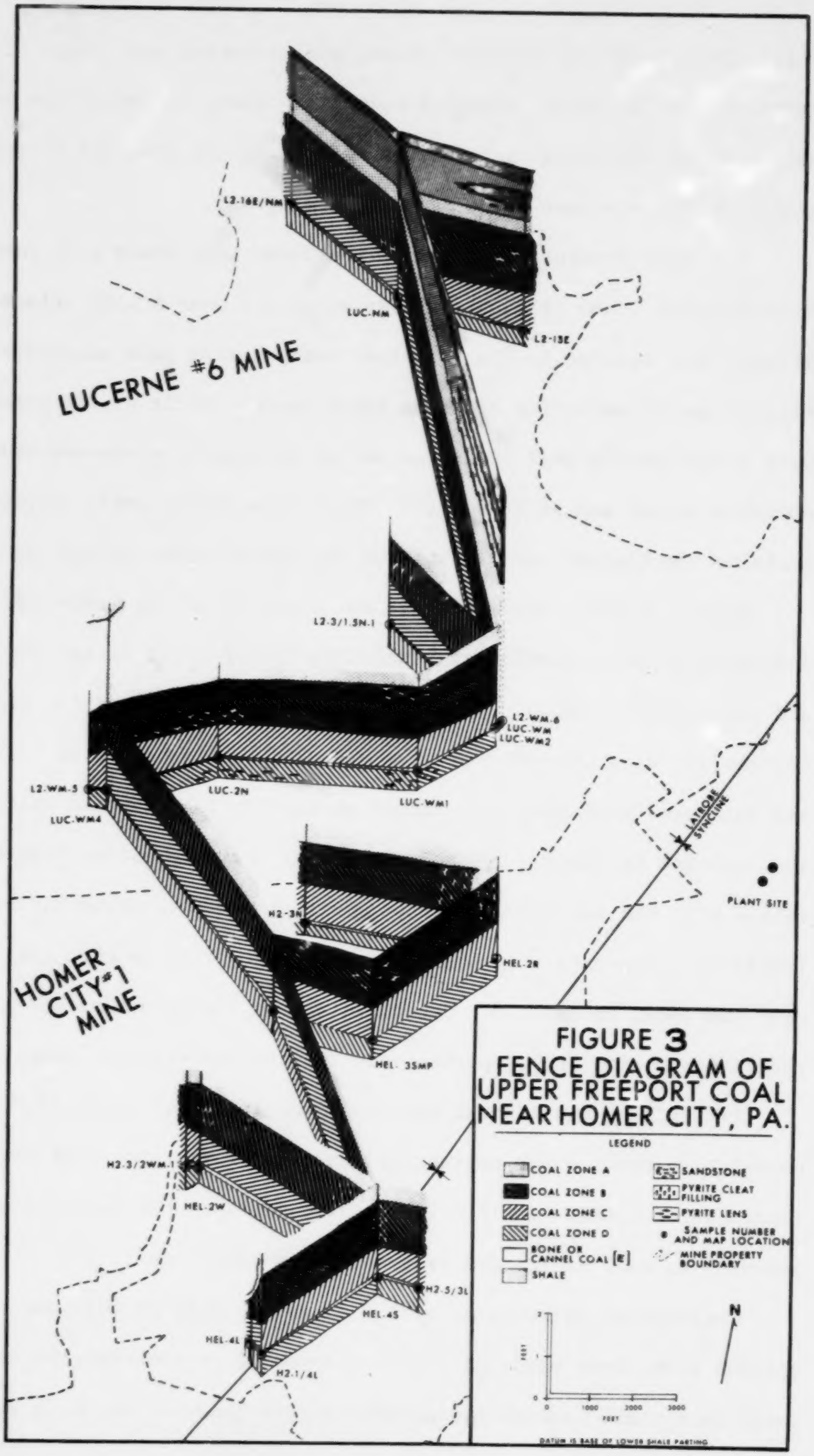

FIGURE 3
FENCE DIAGRAM OF UPPER FREEPORT COAL NEAR HOMER CITY, PA.

LUCERNE #6 MINE
HOMER CITY #1 MINE
L2-16E/NM
LUC-NM
L2-13E
L2-3/1.5N.1
L2-WM-6
LUC-WM
LUC-WM2
L2-WM-5
LUC-WM4
LUC-2N
LUC-WM1
LATROBE SYNCLINE
PLANT SITE
H2-3N
HEL-2R
HEL-3SMP
H2-3/2WM-1
HEL-2W
H2-5/3L
HEL-4S
HEL-4L
H2-1/4L
LEGEND
COAL ZONE A
COAL ZONE B
COAL ZONE C
COAL ZONE D
BONE OR CANNEL COAL [E]
SHALE
SANDSTONE
PYRITE CLEAT FILLING
PYRITE LENS
SAMPLE NUMBER AND MAP LOCATION
MINE PROPERTY BOUNDARY
N
2
1
0
FEET
0
1000
2000
3000
FEET
DATUM IS BASE OF LOWER SHALE PARTING

bearing) which is of sufficient size and form as to be easily removed by physical preparation. Pyrite concentrations are lowest in zone C. Zone D commonly contains framboidal pyrite which is difficult to remove by physical preparation because of the small size of the framboids and their association with vitrinite.

Scanning-electron microscope and electron-microprobe analysis of the Upper Freeport coal were used to determine maceral and mineral associations for certain elements. These analyses show that: 1) arsenic tends to be associated with pyrite in the B zone of the Upper Freeport coal; 2) Zn and Cu are present as sulfide minerals; 3) much, if not all, of the Se is in a lead selenide and lead is also present in a lead sulfide; 4) chlorine is bound organically in vitrinite. The chlorine content of the Upper Freeporrt is lowest in the D zone and increases through the B zone where it attains concentration levels of approximately 0.2 weight percent; 5) the rare-earth elements predominantly occur as phosphates and to a lesser extent are associated with silicates; and 6) chemical analyses indicate that organic sulfur content of the Upper Freeport coal of the study area averages 0.6 weight percent. Preliminary electron-microprobe data tend to substantiate this value with organic sulfur in vitrinite $\geq$exinite> inertinite (Minkin et al., 1979). Most of the organic sulfur is in vitrinite because this is the most abundant maceral.

Preliminary data from the float-sink studies indicate the following: 1) much of the type of pyrite which commonly occurs in the B zone of the coal will be eliminated by coal preparation. This will include most of the arsenic in the coal, and 2) below specific gravities of 1.40 on a whole coal basis, particle size (+1/4", 1/4" x 8 m, and 8m x 100m) reduction does not liberate those elements which correlate with ash content. At specific gravities 1.40 and greater (float 1.6, float 1.8 and sink 1.8 Sp.G.) particle-size reduction liberates increasing amounts of the mineral matter. There are known exceptions to this preliminary generalization because Li and F tend to be concentrated in the 1/4" sink 1.8 Sp.G. fraction rather than in the 8m x 100m sink 1.8 Sp.G. fraction. The cause of such anomolies is currently being investigated.

Conclusions

The mineral matter content of the Upper Freeport coal of the Homer City, Pa. study area is genetically related to a complex set of geologic, geochemical and paleobotanical variables. From statistical analysis, the genesis of the mineral matter content has been divided into 1) ash related, (excluding the pyrite and calcite components), 2) pyrite related, and 3) calcium related. Those elements which positively correlate with the ash (table 1) probably accumulated contemporaneously with the peat; the most probable sources include 1) mineral matter incorporated by plants, 2) detrital minerals and dissolved elements which were incorporated during the peat stage of coal formation, and 3) a combination of plant, detrital and geochemical origin. Some of the ash-correlative elements were later mobilized and precipitated as authigenic mineral phases (i.e., PbSe, PbS, ZnS, $CuFeS_2$). On the basis of preliminary statistical analysis, a genetic relationship between the coal ash and the fusinite-semifusinite content of the coal is apparent. Fusinite and semifusinite are generally believed to be derived from oxidized plant material. Oxidation of organic material during the peat stage of coal formation would concentrate mineral-matter constituents. Therefore, as the fusinite and semifusinite of the coal increases, the ash content increases.

From preliminary studies, the pyrite in the Upper Freeport is usually concentrated in the top and/or bottom zones of the bed throughout the Homer City dedicated reserves. Genetically, pyrite content is apparently unrelated to the bulk of the coal ash. This conclusion is based on statistical analysis

	Ash	Org S	Si	Al	Mg	Na	K	Ti	B	Ba	Be	Cd	Ce	Co	Cr	Cs	Cu	Eu	F	Ga	Gd	Hf	La	Li	Lu	Mn	Mo	Nb	Nd	Ni	Pb	Pr	Rb	Sb	Sc	Se	Sm	Sn	Sr	Tb	Th	U	V	Y	Yb	Zn	Zr
Ash		-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Org S	-		-	-	-	-	-	-	-	-	.	-	-	.	-	-	-	-	-	-	-	-	-	-	-	.	.	-	-	-	-	.	-	.	-	.	-	.	.	-	-	-	-	-	-	-	-
Si	+	-		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Al	+	-	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Mg	+	-	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Na	+	-	+	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
K	+	-	+	+	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
	+	.	+	+	+	+	+		.	.	+	+	+	+	+	.	.	+	.	+	+	.	+	.	+	+	.	+	+	+	+	.	+	.	+	.	+	.	.	+	.	.	.	+	+	+	+
Ti	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
B	+	-	+	+	+	+	+	+		+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	.	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+
Ba	+	-	+	+	+	+	+	+	+		+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Be	+	.	+	+	+	+	+	+	+	+		+	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Cd	+	-	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	.	+	+	+	+	+	+	.	+	+	+	+	+	+
Ce	+	-	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Co	+	.	+	+	+	+	+	+	.	.	+	+	+		+	.	+	+	.	+	+	+	+	.	+	+	.	+	+	+	+	.	+	+	+	+	+	.	.	+	.	+	+	+	+	+	+
Cr	+	-	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Cs	+	-	+	+	+	+	+	+	+	+	+	+	+	.	+		+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Cu	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	.	+	+	+	+	+	.	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+
Eu	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	.	+	+	+	+	.	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+
F	+	-	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+		+	+	+	+	+	+	.	.	+	+	+	+	.	+	.	+	+	+	.	+	+	+	+	+	+	+	+	+
Ga	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Gd	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Hf	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
La	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Li	+	-	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	+	.	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+
Lu	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Mn	+	.	+	+	+	+	+	+	.	+	+	+	+	+	+	.	.	+	.	+	+	+	+	+	+		.	+	+	+	+	.	+	.	+	+	+	+	.	+	.	.	.	+	+	+	+
Mo	+	.	+	+	+	+	+	+	+	+	+	+	.	.	+	+	+	.	.	+	+	+	+	+	+	.		+	+	+	.	+	+	+	+	.	.	.	+	.	.	+	+	+	.	+	.
Nb	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+
Nd	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Ni	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+		+	.	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+
Pb	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+		.	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Pr	+	.	.	.	+	.	.	.	.	.	.	.	.	.	.	.	.	.	.	+	+	.	.	.	.	.	+	+	.	.	.		.	.	.	.	.	.	.	.	.	.	.	+	.	.	+
Rb	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.		.	+	.	+	+	+	+	+	+	+	+	+	+	+
Sb	+	.	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	.	+	+	+	+	+	+	.	+	.	+	+	+	.	.		+	.	+	.	.	+	.	+	+	+	+	.	.
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Sm	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	.	+	+	+	+		+	+	+	+	+	+	+	+	+	+
Sn	+	.	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	.	+	+	+	+	+	+	+	.	+	+	+	+	.	+	.	+	.	+		+	+	+	+	+	+	+	+	+
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Tb	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	.	+	+	+	+	+	+	+		.	+	+	+	+	+	+
Th	+	-	+	+	+	+	+	+	+	+	+	.	+	.	+	+	.	.	+	+	+	+	+	+	+	.	.	+	+	.	+	.	+	.	+	.	+	+	.	.		+	+	.	+	.	+
U	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	.	+	.	+	.	+	+	+	+	+		+	+	+	+	+
V	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	.	+	+	+	.	+	+	+	+	+	+		+	+	+	+
Y	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+		+	+	+
Yb	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	.		+	+
Zn	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	.	+	+	+	+	+	+	.	+	+	+	+		+
Zr	+	-	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	.	+	+	+	+	+	+	.	+	+	+	+	+	+	+	+	+	+	+	+	

Table 1. Correlations among ash related elements at the 95% confidence level.
(+) indicates a positive correlation; (-) indicates a negative correlation;
(.) indicates there is no correlation

	Oxygen	Total Sulfur	Pyritic Sulfur	Fe_2O_3	MnO	P_2O_5	As	Co	Ge	Hg	Mn	Sr
Oxygen		-	-	-	-	+	.	.	-	-	-	+
Total Sulfur	-		+	+	+	.	+	.	+	+	+	-
Pyritic Sulfur	-	+		+	+	-	+	+	+	+	+	-
Fe_2O_3	-	+	+		+	.	+	+	+	+	+	.
MnO	-	+	+	+		.	.	+	+	.	+	.
P_2O_5	+	.	-	.	.		.	.	.	.	.	+
As	.	+	+	+	.	.		.	+	+	.	.
Co	.	.	+	+	+	.	.		+	+	+	.
Ge	-	+	+	+	+	.	+	+		+	+	-
Hg	-	+	+	+	.	.	+	+	+		.	-
Mn	-	+	+	+	+	.	.	+	+	.		.
Sr	+	-	-	.	.	+	.	.	-	-	.	

Table 2. -- Correlations among pyritic sulfur related elements at the 95% confidence level. (+) indicates a positive correlation; (-) indicates a negative correlation; (.) indicates no correlation..

	CaO	Fe_2O_3	MnO	P_2O_5	SO_3	Mn	Mo	Sr	Th	Ti
CaO		+	+	+	+	+	+	+	-	+
Fe_2O_3	+		+	.	+	+	+	.	.	+
MnO	+	+		.	+	+	.	.	.	.
P_2O_5	+	.	.		+	.	.	+	.	+
SO_3	+	+	+	+		+	+	+	.	+
Mn	+	+	+	.	+		.	.	.	.
Mo	+	+	.	.	+	.		+	.	+
Sr	+	.	.	+	+	.	+		.	+
Th	-	.	.	.	-	.	.	.		-
Ti	+	+	.	+	+	.	+	+	.	

Table 3. -- Correlations among calcium (reported as CaO) related elements at the 95% confidence level. (+) indicates a positive correlation; (-) indicates a negative correlation; (.) indicates no correlation.

as well as vertical and lateral variation of the pyrite and ash throughout the coal reserve. The pyrite which formed during the preburial peat stage of coal formation is probably limited to framboids which may be difficult to remove by physical coal preparation. The pyrite in the top benches (A and B zones) probably formed after burial but before compaction was complete. Much of the pyrite in the A and B zones is relatively large and can be removed by physical preparation. These conclusions on preparation characteristics of the various types of pyrite are currently being evaluated on float-sink samples.

The calcium in the coal bed is primarily in authigenic calcite in the coal and in cleats. Much of the calcium may have been fixed during the peat stage by ion exchange and/or as calcium salts of humic acids. Liberation of CO_2 and organically bound calcium during coalification may have resulted in the formation of calcite.

The origin of the calcium in the coal may be highly significant. The buffering effect of calcium-carbonate species supplied to the ancestral peat may have aided in the retention of much of the ash-correlative mineral matter as well as in permitting anerobic bacterial generation of sulfide species. Low pH may cause leaching of mineral matter whereas higher pH values may favor retention.

Preparation characteristics for coal from a given coal-bed reserve are predetermined by the geologic history of the bed. From the data obtained thus far in the present investigation, it seems assured that the geologic controls on coal quality and preparation characteristics can be determined. If this is true, then basic geologic research will rapidly become an integral part of resource assessment, and coal petrology will be extensively used in preparation plant-quality control.

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INTERPRETING STATISTICAL VARIABILITY

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ABSTRACT

The variability of averages of coal characteristics as a function of sample size is considered in this paper. An exploratory application of the methods of geostatistics is made to 1970 data on lbs SO_2/million Btu for the Helen mine. The application is made subject to several important qualifications including, for example, the requirement that successive mining days are equivalent to sampling at uniformly spaced locations along a straight line in a coal seam. The resulting empirical variogram is found to be well-fitted by the standard Matheron spherical scheme. A formula is derived for using either the empirical or fitted variogram to compute the predicted variance of an average based on n successive daily measurements. For the data examined the predicted variances as a function of sample size show good agreement with observed variabilities. These results suggest that the methods of geostatistics may have important applications to a wide variety of coal sampling problems.

INTRODUCTION

In order to assess the quality of coal it is necessary to draw samples and make a variety of laboratory measurements. Such measurements frequently include determinations of the weight percentages of sulfur, ash, moisture, and Btu's per pound. These measured characteristics of coal are often subject to considerable statistical variability in repeated samples. In addition to the inherent variability due to inhomogenieties within a coal seam, other possible sources of variability include the location of the sample, the size, shape, and orientation of the sample, handling and processing methods, laboratory and analytical procedures, etc.

In general, statistical methods are required to treat data showing large amounts of statistical variability. Such methods typically treat the data in terms of averages (as measures of "signals") and variances or standard deviations (as measures of "noise"). Of special importance in sampling procedures is the variance of a mean based on n observations $\sigma^2_{\overline{y}(n)}$ and its relation to the variance of the measurements σ^2_y of the individual measurements. In its simplest form this relation is given by the expression:

$$\sigma^2_{\overline{y}(n)} = \sigma^2_y/n, \qquad (1)$$

where n denotes the number of observations in the sample mean $\overline{y}(n)$. This relation indicates that the sample mean is statistically better behaved (less noisy) than the measurements of which it is composed. In fact, if the sample size is increased by a factor of 2, then Equation (1) shows that the variance of the mean of the n measurements is decreased by a factor of 1/2. For classical statistics this relation is fundamental to virtually all problems involving sample size. Once the variance of the individual measurements is known (or estimated), and the desired precision of the average is specified, then Equation (1) is frequently used to determine the sample size to yield the required precision.

It is well known that the fundamental relation given by Equation (1) frequently does not hold for coal data. In general, increasing a sample size by a factor of 2 will not yield averages that are twice as precise. Sometimes it is found that the precision of an average is hardly increased at all by doubling the sample size.

Figure 1 shows a plot of unpublished data for pounds of sulfur per million Btu for successive mining days for the Helen mine, January, 1970, through December, 1975. In general, the plot shows considerable statistical variability superimposed on more slowly varying drifts over time.

Table 1 shows measures of statistical variability for averages based on different sample sizes for data shown in Figure 1. The second row of the table pertains to averages of pounds of sulfur per million Btu averaged over 5 successive mining days. Column 3 shows that a total of 245 such averages were computed over this 6-year time period. The standard deviation of these 5-day averages is shown to be 0.480 pounds of sulfur per million Btu. The coefficient of variation in percent (relative standard deviation) is given in Column 5 by the ratio of entries in Column 4 to those in Column 2. The coefficient of variation for means based on an aggregation interval of 5 days is seen to be 21.1 percent. In other words, the variability associated with such an average is approximately 21 percent of the average value itself.

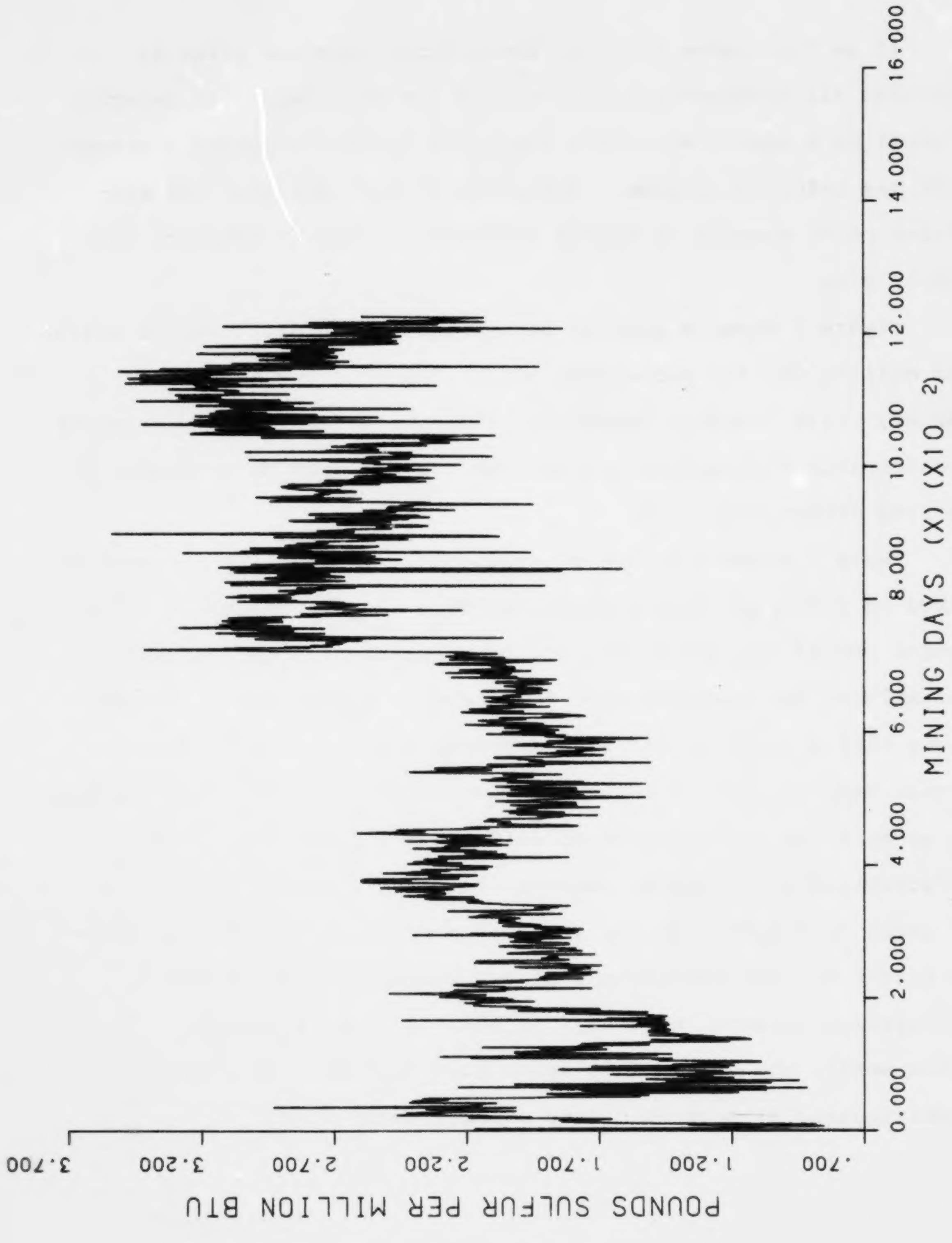

FIGURE 1. POUNDS OF SULFUR PER MILLION BTU FOR SUCCESSIVE MINING DAYS FOR HELEN MINE, JANUARY 1970 THROUGH DECEMBER 1975

TABLE 1. MEASURES OF VARIABILITY FOR POUNDS OF SULFUR PER MILLION BTU AVERAGED OVER SELECTED INTERVALS OF SUCCESSIVE MINING DAYS

Aggregation Interval, Days	Overall Mean	Number of Aggregated Means	Standard Deviation of Aggregated Means	Coefficient of Variation, Percent
		Helen Mine: January 1970--December 1975		
1	2.28	1225	0.507	22.2
5	2.28	245	0.480	21.1
20	2.28	62	0.459	20.1
113	2.29	11	0.418	18.3
226	2.32	6	0.406	17.5

An examination of the results shown in Table 1 indicates that a small reduction in the standard deviation of the aggregated means occurs as the aggregation interval increases approximately through daily, weekly, monthly, 6-months, and yearly time periods. These increases in the time interval of aggregation are represented approximately by factors 5, 4, 6, and 2 for the successive rows of the table. In spite of these relatively large increases in the size of the aggregation interval the reductions in the standard deviations are seen to be relatively small.

In general, the results shown in Table 1 show that the standard deviation of a mean does not decrease in accord with Equation (1). The fourfold increase in sample size from 5 to 20 days, for example, would be expected to decrease the 5-day standard deviations from 0.480 to $0.480/\sqrt{4} = 0.240$ lbs S/million Btu. Instead of a 50 percent decrease in the standard deviation, the decrease is seen to be only 4.4 percent.

It is not difficult to propose possible explanations for the wide discrepencies between actual data and results predicted by Equation (1). The principle explanations include the fact that coal is an inhomogeneous material. Thus, averaging over an increased sample size may, in fact, include coal from different statistical "populations". The standard deviation of the resulting average may not decrease because the sample would then consist of a mixture of different populations of coal, rather than a single population as required by Equation (1). In addition, it is possible that coal samples taken on successive days are highly correlated, so that an unusually high value for sulfur on one day may frequently be followed by an unusually high value on the next day. Equation (1) does not account for such correlations.

A number of investigators have attempted to sort out the complexities of the variability associated with coal measurements. In every instance known to the author an empirical approach has been taken that, in effect, requires the generation of a curve that relates the precision of an average to the size of the sample (weight). Once such a curve is generated, the sample size required to give a specified precision can then be estimated by interpolation. Deeper explanations of empirically attractive procedures frequently result in controversy (Visman, 1969. Duncan, 1971. Visman, Duncan, Lerner, 1974.).

A more fundamental approach to statistical variability has been developed by Matheron (1963,1965,1967) under the name "geostatistics". These techniques have been developed for mining engineers and have been primarily applied to obtain estimates of ore reserves in a variety of foreign countries. To date applications of the methods of geostatistics in the United States are relatively limited.

Because of the possibility that the method of geostatistics would permit a better treatment of statistical variability of coal measurements, an exploratory application of basic geostatistical concepts has been made to coal data. Before presenting these results a brief overview of a few of the central geostatistical concepts is given below. More detailed descriptions can be found in the references listed in a recent Bibliography on geostatistics (Alldredge and Alldredge, 1978); the publications of Royle (1977) are especially recommended.

A Geostatistical Approach

The primary distinction between the methods of geostatistics and conventional statistics is the fact that a sample is characterized both by its measured value and by its sampling location, especially its location with respect to all other sample locations. The sample may be further characterized by its size (volume), shape, orientation, etc. Such information is used to interpret a graphical plot called a variogram that, in turn, is frequently used to partition the overall variability of measured values into two components.

One geostatistical component of the variance is called the "nugget" variance. This variance, symbolized by C_0, is usually relatively small and is conceptually associated either with sample replicates in a laboratory or with samples taken arbitrarily close together in the field. The nugget variance thus represents the possibility that two replicate samples may yield different measured values in a laboratory because of experimental errors, or that two adjacent small-volume samples in the field may yield different measurements because of local discontinuities or inhomogeneities in the sampled material.

As the distance between sample locations is gradually increased the correlation between the pairs of measured values will often decrease, until at some "range", symbolized by "a", the measurements are no longer correlated. Measurements taken at locations separated by distances less than the range are said to be within a mutual "zone of influence". When the individual sampling locations are dispersed over distances greater than the range, the variance among the measurements frequently fluctuates about a maximum level symbolized by C_0+C.

The first objective of a geostatistical analysis consists of generating the variogram. By applying fitting techniques to the variogram it is then frequently possible to determine quantitative estimates of C_0,C, and a. The variogram is constructed from a set of measured values: $y_1,y_2,\ldots,y_n$, ideally taken at uniformly spaced coordinates: $x_1,\ldots,x_n$, along a straight line. The symbol h is used to denote the uniform distance between adjacent measurements. With uniform spacing, sampling points may be separated by distances: h,2h,...,kh,etc. The variogram function represented by the plot is usually symbolized by $\gamma(k)$. The value of $\gamma(1)$ is first computed for all pairs of measured values taken at adjacent sampling locations separated by a distance equal to h; $\gamma(2)$ is then computed for all pairs of measured values separated by a distance equal to 2h, etc., in accord with the following formula:

$$\gamma(k) = \frac{1}{2(n-k)} \sum_{i=1}^{n-k} \left[y_{i+k} - y_i \right]^2 ,k=1,\ldots,n/3. \qquad (2)$$

The distance kh is called a lag of index k. The equation shows that the variogram consists of the average values of the squared differences between the measurements taken at all (n-k) pairs of sampling locations separated by lags of 1,2,...,k, with the maximum value of k approximately equal to n/3.

In order to apply the above concept to run-of-mine coal a number of assumptions must be made. These assumptions include the following:

- the successive daily samples taken from run-of-mine coal can be treated as though they were obtained along a straight line at uniformly spaced locations in the coal seam.
- All samples have the same weight, volume, orientation, etc. within the coal seam.

Both of these assumptions are likely to be incorrect. To the author's knowledge, the daily samples may well represent different mixtures of coal taken from different mining faces, different weights, volumes, orientations, etc. In spite of these difficulties, it is found that many of the computed variograms for coal data yield rather well-defined values for C_0,C, and a.

Figure 2 shows an example of a variogram for pounds of SO_2 per million Btu for daily samples of coal obtained from the Helen mine for 1970. The variogram extends over pairs of mining days separated by lags of 1 mining day, 2 mining days, etc., up to and including lags of 73 mining days. In other words, a mining day is taken to represent the average distance mined in a coal seam in one day. The variogram is seen to increase in a roughly linear manner from a small nugget value of approximately 0.15. The variogram then levels off at a value around 1.20. The leveling-off appears to occur for sampled values separated by approximately 36 mining days. By such a cursory inspection of the variogram. It is seen that the values of C_0,C, and a are approximately 0.15,1.20, and 36, respectively.

A variety of models have been used to fit variogram data. When the graphically estimated values of C_0,C, and a are rather

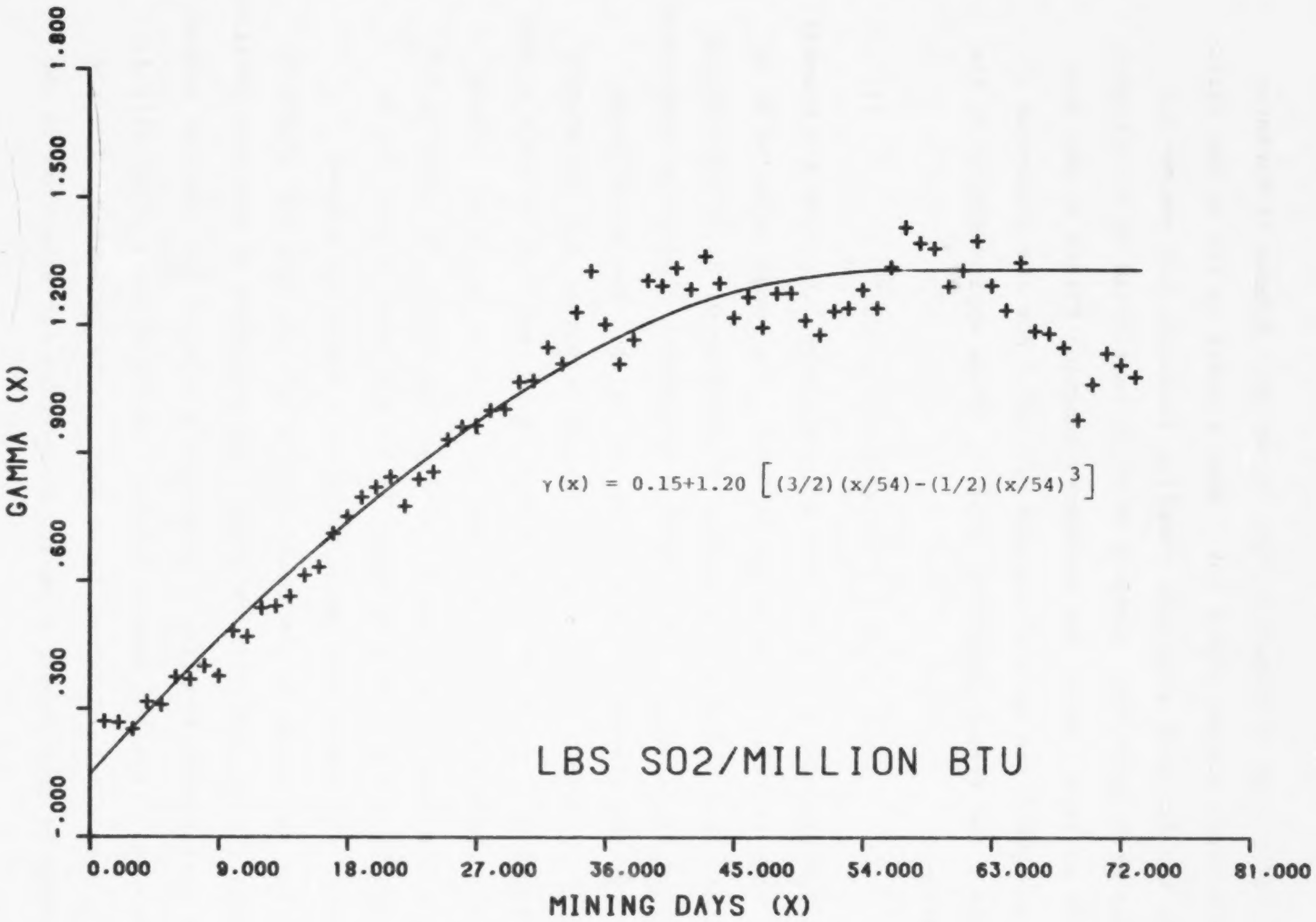

FIGURE 2. VARIOGRAM FOR HELEN MINE, 1970

well-defined as in Figure 2, the "spherical" scheme of Matheron (1963) often yields a good fit. When a model is fit to the variogram, the distance x between sampling locations can assume all values in a continuum, instead of being restricted to an integral number of lags. Thus, the variogram function fitted to the data may be symbolized by $\gamma(x)$ instead of $\gamma(k)$. For the variogram of Figure 2 the fitted spherical model is given approximately by the equation:

$$\gamma(x) = C_0+C\left[(3/2)(x/a)-(1/2)(x/a)^3\right], \qquad (3)$$

with $C_0=0.15$, $C=1.20$, $a=54$, for x/a less than 1.0; when x/a exceeds 1.0, $\gamma(x)$ is taken to be equal to C_0+C. The range value of 54 is obtained from the previous graphical estimate of 36 by multiplying 36 by (3/2) in accord with standard estimation procedures associated with fitting a spherical model (Royle, 1977). The solid curve shown in Figure 2 represents the fitted variogram associated with Equation (3). For most applications it is important to have a good fit for small lag values; for the larger lags, especially those beyond the range, the general level is important, but usually not the detailed fit. On this basis it is seen that a good fit is provided for these data using Matheron's spherical scheme.

The variogram is the basic geostatistical tool for answering virtually every question regarding the precision of averages obtained from statistical sampling. Questions involving the required number of samples, required sample volumes, sample shapes, orientations, etc., must all be referred to an appropriate variogram. For the purposes of this paper, however, we confine our attention to the problem discussed earlier: How does the variability of an average of measured coal characteristics depend on the number of measurements included in the average? In particular, can the methods of geostatistics yield a better relationship than that given by Equation (1)?

A Formula for the Variability of an Average of n Successive Measurements

Based on geostatistical concepts the variability of an average of 2 measurements cannot be determined until the distance between the two sampling locations is specified. In geostatistics the distance x between a pair of sampling locations is usually measured in units of the range as indicated, for example, by the (x/a) terms shown in Equation (3). The variability of a sample mean based on two coal measurements taken 1 mining day apart may generally be expected to be different from that which would be obtained if the measurements were separated by 100 mining days. In general, variabilities of averages are expected to be larger whenever the sample locations lie within their mutual zones of influence, smaller when they do not. The variogram is required to identify and quantify the various possibilities, especially when some sampled locations lie within mutual zones of influence and others do not.

The formula proposed below for computing the variance of an average coal characteristic is based on geostatistical methods. However, the proposed formula has not been identified in the limited geostatistical literature available to the author. Consequently, the reader is cautioned to be critical of the following development, especially with regard to the treatment of the nugget variance.

The proposed formula is first illustrated for an average of 2 measurement y_1 and y_2 taken at sampling locations separated by k lags. A lag matrix is given as follows:

$$\begin{array}{cc} & \begin{array}{cc} x_1 & x_2 \end{array} \\ \begin{array}{c} x_1 \\ x_2 \end{array} & \begin{bmatrix} 0 & k \\ k & 0 \end{bmatrix} \end{array}$$

where the entries in the matrix indicate that a lag of k exists between x_1 and x_2 and lags of zero exist between each point and itself. The γ-values corresponding to these lags are then obtained from the variogram and the following corresponding matrix of γ-values is formed:

$$\Gamma = \begin{bmatrix} \gamma(0) & \gamma(k) \\ \gamma(k) & \gamma(0) \end{bmatrix},$$

where $\gamma(0)$ is set equal to the nugget variance C_0, and $\gamma(k)$ is the value obtained from the plot of the variogram at a lag equal to k. The variability of an average of two successive measurements y_1 and y_2 separated by a lag of k is then given by the following formula:

$$\sigma^2_{\overline{y}(2)} = 2C_0+C-\overline{\Gamma}_2,$$

where

$$\overline{\Gamma}_2 = \left[2\gamma(0)+2\gamma(k)\right]/4.$$

If the two sample locations are separated by a distance at least equal to the range, then $\gamma(k) = \gamma(\infty) = C_0+C$, and with $\gamma(0) = C_0$, it is found that $\sigma^2_{\overline{y}(2)} = C_0+(C/2)$. If the two samples are arbitrarily close together, then $\gamma(k) = \gamma(0) = C_0$ and $\sigma^2_{\overline{y}(2)} = C_0+C$. All other cases lie between these two extremes, so that:

$$C_0+(C/2) \leq \sigma^2_{\overline{y}(2)} \leq C_0+C$$

The same procedure is next applied to obtain the variance of an average of n measurements $y_1, y_2, \ldots, y_n$ assumed to be taken on successive days at sampling locations $x_1, \ldots, x_n$ uniformly spaced on a line. The variance of the mean is given by the formula:

$$\sigma^2_{\overline{y}(n)} = 2C_o + C - \overline{\Gamma}_n, \qquad (4)$$

where $\overline{\Gamma}_n$ denotes the arithmetic average of the variogram $\gamma(k)$-values shown as entries in the following matrix:

$$\Gamma_n = \begin{bmatrix} \gamma(0) & \gamma(1) & \gamma(2) & \ldots & \gamma(n-1) \\ \gamma(1) & \gamma(0) & \gamma(1) & \ldots & \gamma(n-2) \\ \gamma(2) & \gamma(1) & \gamma(0) & \ldots & \gamma(n-3) \\ \ldots & \ldots & \ldots & & \ldots \\ \gamma(n-1) & \gamma(n-2) & \gamma(n-3) & \ldots & \gamma(0) \end{bmatrix} .$$

If the uniform separation between adjacent sample locations exceeds the range, then the entries down the diagonal of the Γ_n matrix are given by $\gamma(0)=C_o$ and all off-diagonal terms are given by $\gamma(\infty)=C_o+C$. The arithmetic average of these γ-values is then found to be given by $\overline{\Gamma}=C_o+(1-(1/n))C$, and from Equation (4) the variance of the sample average is seen to be

$$\sigma^2_{\overline{y}(n)} = 2C_o+C-C_o-(1-(1/n))C$$

with the result that

$$\sigma^2_{\overline{y}(n)} = C_o+(C/n).$$

Again, if all sample locations are arbitrarily close together, then all entries in the Γ-matrix are equal to C_o and it follows that $\sigma^2_{\overline{x}(n)} = C_o+C$. Thus, in every case the variance of the mean is bounded as follows:

$$C_o+(C/n) \leq \sigma^2_{\overline{y}(n)} \leq C_o+C$$

Except for the nugget variance C_0 the upper and lower limits would correspond to the usual statistical case provided C is set equal to the variance of the individual measurements σ_y^2. In geostatistical terms, however, it would appear to be more appropriate to take the variance of individual measurements to be increased by the nugget variance:

$$\sigma_y^2 = C_0+C.$$

For sample locations within their mutual zones of influence, the average value of the variogram values in the Γ-matrix will decrease, and the variance of the average will then increase in accord with Equation (4).

A more formal derivation of Equation (4) is given in Appendix A; an efficient algorithm for computing $\overline{\Gamma}_n$ is given in Appendix B. The derivation of Equation (4) makes use of a basic result in classical statistics for the variance of a linear combination of correlated random variables (Hald, 1952). The derivation shows a close formal relationship between methods of geostatistics and those of classical statistics for correlated variables. In this way it becomes evident that the methods of geostatistics augment those of classical statistics for correlated variables, primarily by introducing C_0 to measure local inhomogeneities and by using the variogram to measure the effects of correlations at specified sampling distances.

An Application to Coal Data

Figure 3 shows the results obtained by applying Equation (4) to the variogram for pounds of SO_2 per million Btu obtained for the Helen mine for 1970-1975 as shown in Figure 2. Figure 3 shows the variance of $\sigma^2_{\bar{y}(n)}$ relative to σ^2_y in accord with the following expression:

$$R = \sigma^2_{\bar{y}(n)} / \sigma^2_y = (2C + C_0 - \bar{\Gamma}_n)/(C_0 + C) \qquad (5)$$

for n varying between 1 and 20 successive measurements. The lower curve shows the theoretical decrease in the relative variance of a mean if the n observations are statistically independent. The uppermost curve shows the predicted decrease in the relative variance of the mean value of lbs SO_2 per million Btu using the fitted variogram, shown in Equation (3), for the 1970 sulfur data for the Helen mine. The broken curve shows the relation obtained when the empirical variogram values are used in Equation (4) instead of those obtained from the fitted smoothed curve shown in Figure 2. The data points shown in Figure 3 correspond to the relative variances computed for Helen data 1970-1975.

In general, the agreement between the actual and predicted values appear to be rather good for the two curves based on the variogram. For small values of n the results suggest that the actual values of the empirical variogram may give better results than the smoothed variogram; for large values of n, there is little difference between the results obtained using the empirical and smoothed variograms. In either case the variogram provides much improved predictions for the variance of a mean as a function

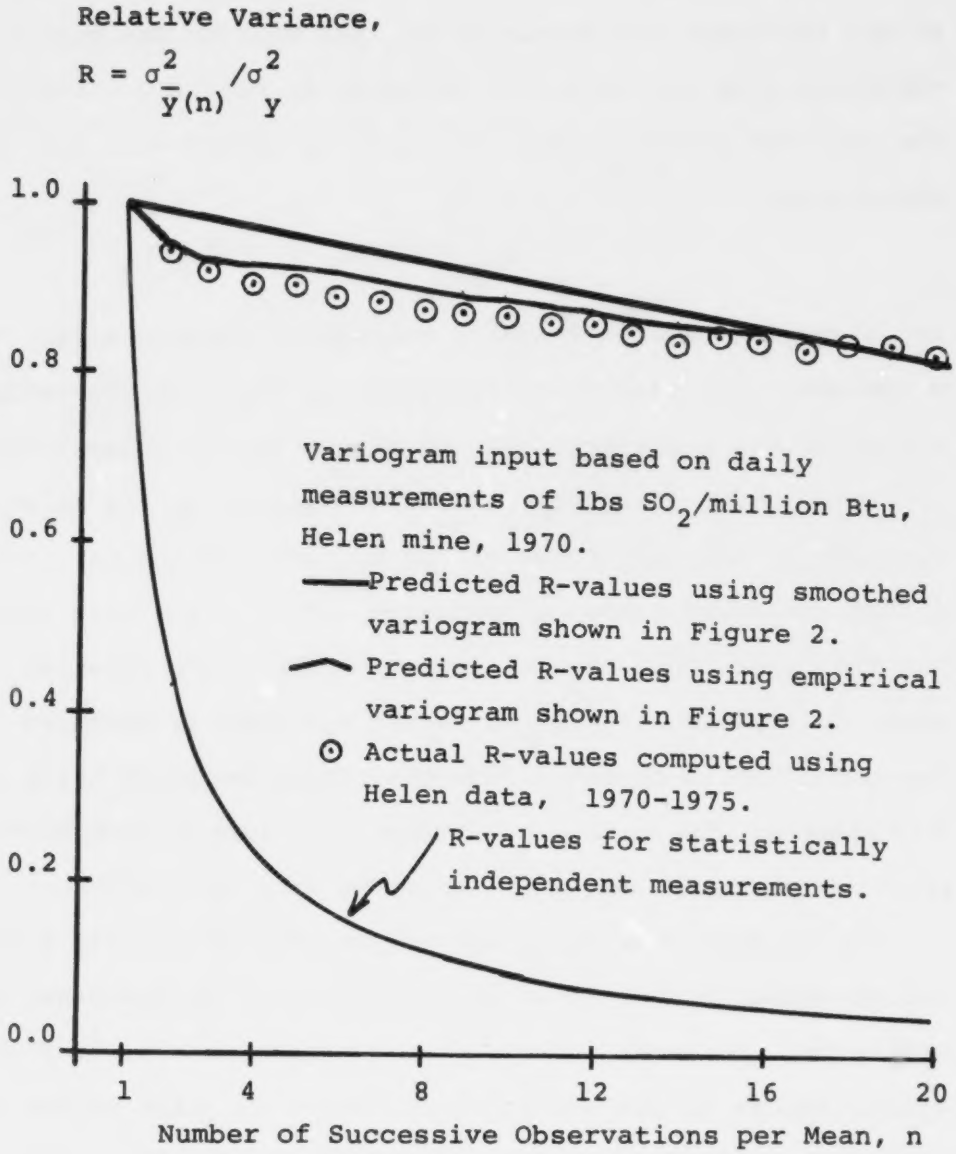

FIGURE 3. Predicted and Actual Relative Variances for a Mean of n Successive Observations

of sample size than that provided by the assumption of statistical independence.

APPENDIX A

Let $y_1,\ldots,y_n$ denote n successive measurements taken at uniformly spaced sampling locations $x_1,\ldots,x_n$ along a straight line. If the variogram of the measurements can be represented by a Matheron scheme:

$$\gamma(x) = C_0+C\left[(3/2)(x/a)-(1/2)(x/a)^3\right],$$

where x denotes the distance between a pair of sampling locations, and C_0, C, and a denote fitted parameters, then the variance of the arithmetic mean of the y-values is given by the following formula:

$$\sigma^2_{\overline{y}(n)} = 2C_0+C-\overline{\Gamma},$$

where $\overline{\Gamma}$ denotes the arithmetic mean of the Matheron γ-values associated with the n^2 distances between sampling locations for all possible pairs of y-values.

To obtain this formula we first note that the expected value of the variogram function is given by $\gamma(k) = \sigma^2_y(1-\rho(k))+C_0$, where C_0 has been added to provide a residual nugget variance. The average value of $\gamma(k)$ over all lags associated with all pairs of sampling locations is then given by $\overline{\Gamma} = \sigma^2_y(1-\overline{\rho})+C_0$. From the statistics of correlated variables $\overline{\rho} = \sigma^2_{\overline{y}(n)}/\sigma^2_y$, and this substitution yields $\sigma^2_{\overline{y}(n)} = C_0+\sigma^2_y-\overline{\Gamma}$. The desired result is then obtained by putting $\sigma^2_y = C_0+C$.

APPENDIX B

Let Γ_n represent the sum of the entries in the following matrix of γ-values:

$$\Gamma = \begin{bmatrix} \gamma(0) & \gamma(1) & \ldots & \gamma(n-1) \\ \gamma(1) & \gamma(0) & \ldots & \gamma(n-2) \\ \ldots & & & \\ \gamma(n-1) & \gamma(n-2) & \ldots & \gamma(0) \end{bmatrix}$$

By considering the sub-matrix associated with Γ_{n-1} it is seen that

$$\Gamma_n = \Gamma_{n-1}+2\left[\gamma(0)+\ldots+\gamma(n-1)\right]-\gamma(0), n=2,3,\ldots,$$

where Γ_1 is defined to be equal to $\gamma(0)$. This relation then permits the sums $\Gamma_2, \Gamma_3, \ldots$ to be computed recursively. The required averages are then given by $\overline{\Gamma}_n = \Gamma_n/n^2, n=1,2,\ldots$.

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AN OVERVIEW OF EPA COAL CLEANING PROGRAMS

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ABSTRACT

Recent environmental regulations have significantly altered the rules under which pollution control technologies must compete. Potential applications of coal cleaning and the resulting research and development goals have been affected.

Although the more stringent SO_2 emission standards being placed on some sources effectively preclude coal cleaning as a sole means of compliance, recent studies indicate that coal cleaning in conjunction with flue gas desulfurization can provide substantial cost benefits in certain applications. Coal preparation has the additional advantage of removing some harmful trace elements from the coal prior to combustion.

In order to evaluate and enhance the position of coal preparation in the pollution control technology mix of today and the future, EPA maintains a three-part program. Its goals are: (1) to assess and develop coal cleaning processes; (2) to assess the environmental impact of coal cleaning; and (3) to develop pollution control technology for coal cleaning processes.

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INTRODUCTION

Two major goals of the National Energy Policy are the expanded use of domestic coal supplies to replace imported oil, and abatement of the adverse environmental impacts which result from coal use. The legislation which gives substance to the second goal is contained in the Clean Air Act Amendments of 1977, Federal Water Pollution Control Act Amendments of 1977, The Resource Conservation and Recovery Act of 1976, and The Toxic Substances Control Act of 1976.

In recent years coal cleaning, once used solely to remove mineral matter from coal, has been recognized as a viable method of removing sulfur from coal prior to combustion. The technique is so successful that it is gaining recognition as an efficient and relatively inexpensive method of making additional supplies of environmentally acceptable coal available. The remainder of this paper will develop a historical perspective to EPA's coal cleaning program, an outline of the regulations to which it is responsive, objectives of the program, and some significant results which have been achieved.

BACKGROUND

Although a Federal program of research in air pollution was initially authorized in 1955, no substantial effort was put forth in the area of coal cleaning until the passage of The Clean Air Act in 1963. This Act called for an expanded Federal research and development program with special emphasis on the investigation of sulfur oxide pollution from the burning of coal and fuel oil. In response to this mandate, the Department of Health, Education and Welfare, the predecessor of EPA, began to study coal cleaning as a means of sulfur oxide control in 1964.

The Air Quality Act of 1967 gave an additional impetus to the effort by directing HEW to establish the National Center for Air Pollution Control, formerly known as the Division of Air Pollution of the Public Health Service. At the Center coal cleaning studies continued and began to assume many of the aspects which characterize the present program (U. S. Congress, 1968).

In 1970 legislation was passed which established the Environmental Protection Agency. Today the coal cleaning research program which was initiated in 1964 by HEW is being carried on by the Fuel Process Branch of EPA's Industrial Environmental Research Laboratory at Research Triangle Park, North Carolina.

REGULATIONS

The following portions of the more important environmental regulations are discussed briefly, either because they refer to a pollution problem which coal cleaning can ameliorate, or because they place restrictions on pollution from the coal cleaning technology itself. EPA's research and development activities under the coal cleaning program are periodically modified to make them responsive to changing regulatory requirements and energy goals.

Air

In accordance with the Clean Air Act of 1970, EPA has set primary and secondary ambient air quality standards to protect public health and welfare, respectively. Regulated pollutants directly related to the use of coal include sulfur oxides, nitrogen oxides and particulate matter.

Section 111 of the Clean Air Act requires EPA to promulgate emission standards for new stationary sources. As originally promulgated, these New Source Performance Standards were emission limitations and could be met with any control device or system (40 CFR 60, 1976). The Clean Air Act Amendments of 1977 substantially altered the format of these standards. New stationary sources must now: 1) use best available control technology; 2) use a method of continuous pollution control; and 3) achieve a specified percentage reduction of regulated pollutants from fossil fuel-fired units. While these new regulations by themselves do not affect the applicability of coal cleaning, the definition of best available control technology and the percentage reductions which are assigned to the various pollutants could significantly restrict the use of cleaned coals as a sole means of compliance.

To comply with the intentions of the new regulations, EPA has proposed revised New Source Performance Standards for utility boilers in the future. The revisions will require: 1) an 85 percent reduction in sulfur between extraction and stack emissions; 2) that sulfur oxide emissions not exceed 1.2 lb* $SO_2/10^6$ BTU of heat input; 3) no further control if emissions are 0.2 lb $SO_2/10^6$ BTU.

Background studies in support of industrial boiler NSPS are currently underway. The format of the regulations, if not the emission and reduction levels, will be similar to those for utility boilers. The extent of coal cleaning's role as a means of compliance for utility and industrial boilers is not presently known.

New Source Performance Standards for air pollutants also apply to coal preparation plants and coal handling facilities. Present regulations restrict particulate emissions from thermal driers and handling facilities to 20 percent opacity. Pneumatic cleaning equipment may not exceed 10 percent opacity (40 CFR 60, 1976).

In addition to the more conventional pollutants generally discussed, the Clean Air Act of 1970 requires EPA to establish a list of "hazardous pollutants" and to propose emission standards for them. Both mercury and beryllium are emitted from coal-fired boilers and are subject to these standards.

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*conversion factors for metric equivalents of non-metric units used in this paper appear near the end of the paper

The Amendments of 1977 specify four unregulated pollutants which EPA must investigate and, if necessary, regulate. These are arsenic, cadmium, polycyclic organic matter and radioactive pollutants. No determination has yet been made in this area. It is known, however, that the coal cleaning process partitions trace elements among the various size-gravity fractions. There is a high probability that coal cleaning can serve as a pre-combustion removal method for some of these elements.

Water

Federal control of industrial water pollution sources is achieved through the issuance of discharge permits under the authority of the Federal Water Pollution Control Act of 1972. These permits stipulate the concentrations of various pollutants allowed in the effluents. Effluent limitations are presently based on the Best Practicable Control Technology currently available (BPT), and must be based on the Best Available Technology Economically Achievable (BATEA) by 1985.

New Source Performance Standards on effluents from categories of industrial sources are required by Section 306 of the Act and intended to be the most stringent of the three levels of limitations. Coal preparation plants are in a category for which NSPS have been proposed (40 CFR 434, 1977). Tables 1 and 2 show the proposed limitations for facilities having acid and alkaline effluents prior to treatment. Plants which do not recycle waste water are subject to a "no discharge of pollutants" limitation.

Effluent Characteristic	Effluent Limitations Maximum for Any 1 Day, mg/l	 Average of Daily Value for 30 Consecutive Days Shall Not Exceed, mg/l
Iron, Total	3.5	3.0
Manganese, Total	4.0	2.0
TSS	70.0	35.0
pH	Within the range 6.0 to 9.0	

Table 1. Limitations for acid effluents.

Effluent Characteristic	Effluent Limitations Maximum for Any 1 Day, mg/l	 Average of Daily Value for 30 Consecutive Days Shall Not Exceed, mg/l
Iron, Total	3.5	3.0
TSS	70.0	35.0
pH	Within the range 6.0 to 9.0	

Table 2. Limitations for alkaline effluents.

These regulations, of course, take a fairly simplistic view of what constitutes a pollutant in industrial effluents. This fact was recognized by several environmental groups and in 1975 EPA faced court action by these groups for not having made a thorough assessment of the pollutants discharged into surface waters by industry. The courts concurred with the environmentalists and as a result, EPA was ordered to reassess the BAT effluent limitations in view of a list of 129 specific "priority pollutants."

In the course of this review, 16 coal preparation plants were sampled for concentrations of priority pollutants. Tentatively, 24 of the 129 pollutants have been identified in effluent streams from preparation facilities and ancillary areas. Those pollutants which consistently appear in significant quantities can be expected to be regulated eventually.

Solid Waste

Solid wastes such as those generated by coal preparation have not traditionally fallen under Federal control with respect to the quantities disposed of or the specific means of disposal. In October of 1976, however, Congress passed the Resource Conservation and Recovery Act (RCRA). Although the ramifications for coal combustion and coal cleaning wastes are not yet known, a determination that these products are hazardous wastes would subject them to the most stringent applications of the law.

PROGRAM OBJECTIVES

With this historical perspective and regulatory framework in mind, EPA has structured a program with three objectives: 1) to assess and develop coal cleaning processes; 2) to assess the environmental impact of coal cleaning; and 3) to develop pollution control technology for coal cleaning processes.

Table 3 outlines the present interagency program which EPA is funding. The budget for fiscal 1978 was approximately eight million dollars.

PROGRAM OUTPUTS

Technology Assessment

Improved techniques for the preparation of fine coal are needed to enhance sulfur removal and coal energy recovery. The primary objectives of the technology assessment and development activities are to evaluate the potential cleanability of U.S. coals, and the performance and costs of commercial equipment which can be used for the beneficiation of fine coal. The development of chemical coal cleaning processes is supported, as is the applied research necessary to characterize the basic mechanisms which govern beneficiation processes.

Assessment of Coal Cleaning for SO_2 Emission Control

The 1977 Clean Air Act Amendments provide a new impetus for evaluating coal cleaning as an SO_2 emission control technique. The regulations mandated by this legislation have significantly altered the positions of competing technologies. Studies are in progress to assess the applicability of coal cleaning as a means of SO_2 control with respect to other control technologies for: 1) existing boilers regulated under SIPs; 2) NSPS for coal-fired steam generators; 3) revised NSPS for utility boilers; and 4) NSPS for industrial boilers. Preliminary results from these studies suggest that:

TABLE 3. Active Interagency Coal Cleaning Projects (1977-1978)

Project Title (Contract, Grant, or Interagency Agreement)	Organization Directing Work	Organization Performing Work	Objectives
TECHNOLOGY ASSESSMENT AND DEVELOPMENT			
Coal Cleanability (IAG-D6-E685)	DOE(a)	DOE(a)	Determine desulfurization potential of U.S. coals by size reduction and specific gravity separation.
Coal Cleaning Technology Assessment and Development (68-C2-2199)	EPA	Versar, Inc.	Evaluate performance and costs of equipment for removing sulfur from coal.
Interim Support for Homer City Test Program (68-02-2639)	EPA/DOE(b)	Chem Systems/Pennsylvania Electric Co.	Provide test planning and initial test support for the Homer City Coal Cleaning Demonstration Program.
Dense Media Cyclone Pilot Plant (IAG-D6-E685)	DOE(a)/EPRI/ PENELEC/EPA	DOE(a)	Evaluate effects of cyclone design and operation variables on separation of fine coal and pyrite.
Demonstration of Coal-Pyrite Flotation (IAG-D6-E685)	DOE(a)	Heyl and Patterson Co./Barnes and Tucker Co.	Commercial testing and operation of two stage coal-pyrite flotation process developed by DOE(a).
Adsorption-Desorption Reactions in Pyrite Flotation (IAG-D6-E685)	DOE(a)	University of Utah	Evaluate the adsorption-desorption mechanisms which control performance in the DOE(a) two stage coal-pyrite flotation process.
High Gradient Magnetic Separation (IAG-D5-E685)	DOE(a)	General Electric Co.	Evaluate technical feasibility of high gradient magnetic separation for removing pyrite from coal.
Surface Phenomena in Dewatering of Fine Coal (IAG-D6-E685)	DOE(a)	Syracuse Univ.	Evaluate phenomena governing the effectiveness of surfactants in reducing the final moisture content of coal vacuum filter cakes.
Coal Cleaning Test Facility (IAG-D6-E685)	DOE(a)	Birtley Engineering Corp. Williams, Trebilcock and Whitehead	Design a DOE coal cleaning test facility. Provide architectural and engineering plans.

continued

TABLE 3. (continued)

Project Title (Contract, Grant, or Interagency Agreement)	Organization Directing Work	Organization Performing Work	Objectives
Coal Preparation Plant Computer Model (IAG-D6-E685)	EPA/DOE[(a)]	DOE[(a)], U. of Pittsburgh, and Battelle	Develop computer model capable of predicting the performance of coal preparation plants.
Engineering/Economic Analysis of Coal Preparation Operation and Cost (IAG-D6-E685)	DOE[(a)]	Hoffman-Muntner Corp.	Determine the costs of cleaning for eight representative coal preparation plants - from jig plants to complex heavy media plants.
Reactor Test Project for Chemical Removal of Pyritic Sulfur from Coal (68-02-1880)	EPA	TRW Defense and Space Systems Group	Evaluation of the Meyers chemical coal cleaning process in a 1/3 tph reactor test unit.
Microwave Desulfurization of Coal (68-02-2172)	EPA	General Electric	Evaluate the feasibility of coal desulfurization by microwave treatment.
Battelle Hydrothermal Process Improvement Studies (68-02-2187)	EPA	Battelle Columbus Laboratories	Evaluate methods for liquid/solid separation and leachant regeneration.
Evaluation of Chemical Coal Cleaning Processes (IAG-D5-E685)	DOE[(c)]	Bechtel	Evaluate relative costs and performances of selected chemical coal cleaning processes.
Hydrodesulfurization of Coal (68-02-2126)	EPA	Institute of Gas Technology	Evaluate desulfurization of coal by mild oxidative treatment followed by devolatilization.
Environmental Studies on Coal Cleaning Processes (IAG-D5-E721)	EPA	Tennessee Valley Authority (TVA)	Evaluate technology for controlling pollution at TVA coal preparation plants.
Cost Evaluations of Coal Cleaning and Scrubbing (IAG-D5-E721)	EPA	TVA	Evaluate relative costs of coal cleaning and scrubbing in complying with various SO_2 emission standards.
ENVIRONMENTAL ASSESSMENT			
Environmental Assessment of Coal Cleaning Processes (68-02-2163)	EPA	Battelle Columbus Laboratories	Evaluate pollution resulting from coal cleaning, transportation and storage. Evaluate coal cleaning as an SO_2 emission control technique.

continued

TABLE 3. (continued)

Project Title (Contract, Grant, or Interagency Agreement)	Organization Directing Work	Organization Performing Work	Objectives
Trace Elements and Mineral Matter in U.S. Coals (R804403)	EPA	Illinois State Geological Survey	Characterize the elemental constituents and mineralogy of U.S. coals.
Geology of Contaminants in Coal (IAG-D6-E685)	EPA	U.S. Geological Survey	Characterize coal resources west of the Mississippi as to their elemental and mineralogic composition. Evaluate the geologic factors which affect or control coal cleanability.
Trace Element Characterization of Coal Preparation Wastes (IAG-D5-E681)	EPA/DOE(b)	Los Alamos Scientific Laboratory (LASL)	Characterize trace element and mineralogic associations in coal preparation wastes.
A Washability and Analytical Evaluation of Potential Pollution from Trace Elements (IAG-D6-E685)	DOE(a)	DOE(a)	Evaluate partitioning of trace elements in 10 U.S. coals during specific gravity separation.
Evaluation of the Effects of Coal Cleaning on Fugitive Elements (IAG-D6-E685)	DOE(a)	Bituminous Coal Research Inc.	Evaluate partitioning of trace elements during preparation and use.
DEVELOPMENT OF POLLUTION CONTROL TECHNOLOGY			
Control of Trace Element Leaching from Coal Preparation Wastes (IAG-D5-E681)	EPA/DOE(b)	LASL	Determine leachability of trace elements from coal preparation wastes and evaluate pollution control methods.
Control of Blackwater in Coal Preparation Plant Recycle and Discharge (IAG-D5-E685)	DOE(a)	Pennsylvania State University	Characterize blackwater generated by coal preparation plants and assess potential control methods.
Stabilization of Coal Preparation Waste Sludges (IAG-D5-E685)	DOE(a)	Dravo Lime	Collect coal preparation plant sludges and perform laboratory stabilization tests.

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a - Department of Energy, Coal Preparation and Analysis Laboratory, Pittsburgh, Pennsylvania
b - Department of Energy, Office of Environment, Washington, D.C.
c - Department of Energy, Office of Energy Technology, Washington, D.C.

1) where technically feasible, cost savings from the use of physical coal cleaning (PCC) can be realized for both utility and industrial boilers, particularly those boilers with low capacity factors;

2) PCC appears to be unable to meet revised NSPS for utility boilers unless combined with FGD;

3) there apparently are cases under current Federal and State standards where the combined use of PCC and FGD is more cost effective than the use of FGD alone;

4) chemical coal cleaning may be competitive with FGD for small industrial boilers having low capacity factors;

5) the most probable use of chemical coal cleaning is in combination with PCC to provide lower sulfur levels than can be achieved by PCC alone.

Coal Cleanability

The DOE Coal Preparation and Analysis Group at Bruceton, Pennsylvania is conducting laboratory experiments to determine the liberation potential of pyrite from the principal U.S. coal beds. Over 600 samples have been analyzed thus far. The results of these studies will be used to assess the impact of coal cleaning on SO_2 emissions by determining the feasibility of cleaning various coals.

Technology Assessment

In January of 1977, Versar, Inc. began a project to evaluate the performance of coal cleaning equipment. The emphasis of the program was to be on fine coal cleaning and drying.

Thus far, seven coal preparation plants have been visited by the mobile test laboratory to determine the capabilities of their froth flotation units, heavy media and hydrocyclones in reducing pyrite content in fine coals.

In addition, a study has been completed on coal preparation requirements for synthetic fuel conversion processes. An evaluation of the 11 most promising chemical coal cleaning processes has also recently been completed and published (Contos et al., 1978). Estimated costs for the processes range from $38.50 to $65.72/ton including coal.

Also under the general heading of technology assessment are several projects which are funded by EPA but managed by DOE. Included in this group are two high gradient magnetic separation studies. One project is conducted by General Electric and is an investigation of the removal of pyrite from dry coal powders. The second study is being done by MIT and involves the recovery of magnetite using high gradient magnetic separation techniques. Results of both of these studies are being prepared for publication. Other projects included under this agreement involve characterization of blackwater constituents, a study of the adsorption/desorption reactions in pyrite flotation, and a study of the surface phenomena involved in the dewatering of fine coal.

Homer City Coal Cleaning Demonstration

Construction has been completed on a pilot, multi-stream coal cleaning plant at the Homer City Generating Station Power Complex, Homer City, Pennsylvania. The 1200 ton per hour plant is designed to yield two products; a middling stream containing

4.0 lb $SO_2/10^6$ BTU, and a deep-cleaned stream which contains 1.2 lb $SO_2/10^6$ BTU. Extensive testing of the plant over the next three years will be conducted under the cooperative efforts of EPA, DOE, PENELEC and EPRI.

Meyers Chemical Coal Cleaning Process

A 1/3 ton per hour pilot scale test reactor has been constructed at Capistrano, California for the purpose of evaluating the performance of the TRW Meyers process in chemically removing sulfur from coal. The process operates on the principle of aqueous ferric sulfate leaching and apparently is capable of removing up to 95 percent of the pyritic sulfur. No organic sulfur is removed. The reactor, after 254 hours of test operations on 50,000 lb of coal, has been shut down due to metal corrosion in the primary reactor.

Microwave Desulfurization

Laboratory experiments by the General Electric Company have demonstrated the technical feasibility of coal desulfurization by microwave energy. Pyrite is preferentially excited by the microwaves to produce volatile and water soluble sulfur compounds which can then be removed from the coal. The experiments have also shown that irradiation of mixtures of coal, water and NaOH appears to convert both pyritic and organic sulfur to water soluble sulfides. Present cost estimates suggest that microwave desulfurization should be competitive with other chemical desulfurization techniques.

Environmental Assessment

The overall objectives of the environmental assessment activities have been to characterize coal contaminants and to identify the fate of these contaminants during coal processing and coal use. Initial studies have focused on sulfur and potentially hazardous minor and trace elements contained in coal. Recent studies have been concerned with a wider range of pollutants - those which may be considered hazardous or toxic under the provisions of the Water Pollution Control Act (priority pollutants), the Resource Conservation and Recovery Act (hazardous wastes), the 1977 Clean Air Act Amendments (hazardous air pollutants), or the Toxic Substance Control Act. The basic intent of the environmental assessment activities is to identify pollutants which pose health or ecological threats and devise cost effective strategies for dealing with the pollutants.

Environmental Assessment Project

A three year project to assess the environmental impacts of coal preparation, coal transportation and coal storage is being conducted for IERL-RTP by Battelle Columbus Laboratories. Major project activities include:

1) the development of a technology overview containing a description of all current coal cleaning processes and their associated pollution control problems;
2) the development and performance of an environmental test program to obtain improved data on pollutants from commercial coal cleaning plants;

3) the development of criteria to be used in assessing the potential health and ecological impacts of pollutants from coal cleaning processes;

4) the performance of studies to determine the relative environmental impacts of coal cleaning, FGD, and other SO_2 emission control techniques.

Studies to develop criteria for assessing the relative environmental hazards associated with pollutants resulting from coal preparation, coal transportation and coal storage are nearing completion. The approach has been to characterize the physical and chemical toxicity of pollutant or effluent streams sampled at their respective sources. This differs from the approach taken in environmental impact assessments - the characterization of air, water, and biological quality in the facility under study. The source assessment criteria incorporate methodologies being developed by IERL-RTP and adapt them to coal cleaning processes (Hangebrauck, 1978).

Concurrent with development of source assessment criteria, studies are in progress to select coal cleaning plant sites for environmental testing. A master test plan is being developed to ensure a comprehensive test program and to facilitate the planning and preparation of site-specific test plans for the designated facilities.

Thus far, background studies of the air, water and biological quality in the vicinity of the Homer City Generating Station have been completed in preparation for an environmental assessment of the cleaning plant which has been built at the site. Testing will begin when the plant normalizes operations.

Coal Contaminants

Three distinct programs are directed to the identification and characterization of contaminants in coal. Specifically the research attempts to demonstrate the occurrence, association and distribution of trace element and mineral phases in the coal seam.

One portion of this research, led by the Illinois State Geological Survey, concentrates on coals of the Illinois Basin. This work has three principal goals: 1) to determine the mode of occurrence and distribution of trace elements and minerals in coal seams; 2) to study the mineralogy and genesis of sulfide minerals in coal; and 3) to evaluate the potential for removal of minerals from coal by various preparation techniques.

A second area of investigation is being conducted by the U.S. Geological Survey in Reston, Virginia. This project has dual objectives. One is to determine the geologic factors which affect or control the physical cleanability of coal, and to develop geologic models which can be used to help maximize efficiency and minimize environmental impact from coal mining, cleaning and burning. The second objective is to provide the necessary chemical, physical and mineralogic data on the Nation's coal resources to permit evaluation of the environmental impact resulting from coal preparation and utilization.

The third study in this area, being conducted at the Los Alamos Scientific Laboratory (LASL), deals with the contaminant potential of coal preparation wastes. The research has three distinct phases: 1) to characterize the minerals, trace elements, and their association in coal preparation wastes; 2) to study the effects of weathering and leaching on trace elements in coal wastes; and 3) to identify and evaluate techniques for controlling or preventing trace element contamination from coal waste materials. Phases one and two have been completed and the results published (Wewerka et al., 1976, 1978a, 1978b).

Pollution Control Technology

The subprogram to develop coal cleaning pollution control is in a formative stage. A wide variety of techniques exist for controlling conventional pollutants such as total suspended solids, total particulate emissions and pH. However, as coal cleaning processes evolve and as pollution regulations become more stringent, improvements will be required in pollution control techniques. This portion of the program, therefore, addresses projected as well as current pollution control techniques.

Control of Trace Element Leaching from Coal Preparation Wastes

The Los Alamos Scientific Laboratory is conducting studies to assess the potential environmental contamination from trace elements in coal preparation leachates, and to determine suitable methods for control. Trace element and mineralogic characterization of refuse samples has been completed. Analyses of the leachates from these samples have also been completed.

The control technology assessment includes methods to prevent the leaching of trace elements from coal cleaning wastes and to remove trace elements from the leachate once they have been entrained. Methods evaluated thus far include the addition of lime, limestone, lye and other naturally occurring alkaline materials to the waste material. Calcining is presently being studied. Techniques under consideration for water treatment include reverse osmosis, chelation, alkaline neutralization, permanganate oxidation and others.

Control of Blackwater

Blackwater (process waste water) from coal preparation plants consists of mixtures of fine coal, clay minerals, quartz, calcite, pyrite and other fine-grained mineral particles suspended in water. The composition of these effluents must be known before they can be adequately treated for reuse or discharge. Pennsylvania State University has completed an investigation to characterize the solid constituents in blackwater and to determine the best procedures for treating it (Aplan et al., 1979). The final report is being prepared for publication.

Stabilization of Coal Preparation Waste Slurries

Reject ponds are becoming increasingly undesirable because of safety, environmental and land use considerations. An alternative approach to slurry disposal is the treatment of these wastes to create stable solids.

EPA is funding a project at Dravo Lime Co. to characterize the engineering, physical and chemical properties that affect stabilization of fine wastes from coal preparation plants. The requirements and conditions for stabilizing these wastes with and without additives are being determined.

CONCLUSIONS

The past year has been one of change. Potential applications of coal cleaning, and therefore our research and development goals, have been altered by new environmental legislation and impending energy legislation. Studies are in progress to identify the technical capability and costs of various coal cleaning technologies for removing sulfur and other contaminants in coal. Progress has been made in the development of physical coal cleaning techniques for improved pyrite removal and coal energy recovery. Progress is continuing in the development of chemical coal cleaning processes, but impending environmental standards are causing uncertainties regarding future market applications.

Methodologies have been developed for the environmental assessment of coal preparation processes, and tests are scheduled to begin shortly. The conditions under which trace elements are leached from coal preparation wastes have been identified, and preliminary studies have identified the effectiveness of several pollution control techniques.

CONVERSION FACTORS

ton = 0.907 metric ton

lb = 0.436 kg

BTU = 1055.6 joules

BTU/lb = 2326 joules/kg

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OVERVIEW OF DOE COAL CLEANING PROGRAM

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ABSTRACT

The U.S. Department of Energy has an active program in coal preparation. The program includes coal characterization, physical and chemical cleaning, and economic and market studies to assess the ability of coal preparation to facilitate coal usage in the United States.

The DOE fiscal year 1978 budget in coal preparation is approximately $9.0 million. The DOE fiscal year 1979 coal preparation budget will be $8-14 million, depending on Congressional action.

This paper initially examines why coal preparation is important and how it compares to competitors. After describing the major elements of the DOE coal preparation program, the DOE organizations involved are discussed along with their current and planned projects. Finally, the issues facing DOE and industry in the coal preparation arena are explored.

Introduction

Coal cleaning has recently received attention as a method of meeting environmental regulations. Using advanced coal cleaning techniques to help meet environmental standards is a definite change from conventional coal washing to remove heavy impurities.

This paper discusses the primary environmental standards that will affect coal usage in the United States and how coal preparation stacks up against its competition. Then it describes the U.S. Department of Energy's (DOE) program in coal preparation, including its organization, projects, people, and funding. Finally we hope to stimulate some discussion by exploring the issues facing DOE and industry in coal preparation.

Projected Coal Usage and Applicable Environmental Standards

The general objective of the National Energy Plan (NEP) is to reduce United States' dependence on scarce fuels (oil and gas) while continuing to achieve economic growth and reduction of environmental pollution. The programs outlined in current legislative proposals that will encourage or require increased coal use in the utility and industrial sector include (1) the mandatory coal conversion program, (2) taxation of oil and gas use, while providing tax rebates on coal investments, and (3) gradual deregulation of natural gas.

Environmental goals impact the coal demands generated under the NEP in two ways. First, pollution controls which increase costs and/or unreliability can discourage individuals from responding to the NEP's financial incentives, and/or exempt them from mandatory coal conversion. Second, EPA or state regulations can block the use of coal in regions where national environmental goals cannot be met (i.e., control systems for coal use are not adequate).

The Clean Air Act established two major mechanisms to control air pollutant emissions from stationary sources. New Source Performance Standards (NSPS) are national standards limiting emissions from specified sources. State Implementation Plans (SIP's) establish compliance schedules and emission limitations for all types of sources so as to ensure attainment/maintenance of air quality standards in each state. All boilers are, at a minimum, subject to any applicable SIP requirements, and if a SIP limitation is more stringent than the corresponding NSPS, the SIP is the binding regulation.

In addition to the SIP emission standard or NSPS, new emission sources may be subject to even more stringent levels of control on a case-by-case basis. All major new sources must be individually reviewed and their impacts modeled to ensure that their emissions will not cause more than the allowed degradation of air quality, or prevent attainment of Ambient Air Quality Standards.

For purposes of this analysis, air emission limitations have been divided into five general categories: SIP's applicable to utilities, SIP's for smaller industrial boilers, the current utility NSPS, and anticipated NSPS for both utility and industrial boilers. The basic emission limits for each category for sulfur oxides, nitrogen oxides, and particulates are shown in table 1.

Although air emissions are the primary environmental concern in the firing of coal, associated water discharges and solid waste disposal practices come under Federal regulation. They are important because waste streams are produced in coal cleaning, disposal of coal combustion residues, and processing of exhaust streams. The four Federal laws influencing the disposal of these wastes are Resource Conservation and Recovery Act of 1976, Federal Water Pollution Control Act as amended by Clean Water Act of 1977, Toxic Substances Control Act of 1976, and Safe Drinking Water Act of 1974.

Projections of utility and industrial coal demand for 1985, 1990, and 2000 are presented in figure 1. In general, the 1985 and 1990

Regulation & Source	Sulfur Oxides	Particulates	Nitrogen Oxides
Utility			
State limits[1]	1.0 - 6.0 (2.0) #/MMBtu	0.1 - 0.6 (.3) #/MMBtu	None or 0.7 #/MMBtu
Current NSPS[2]	1.2 #/MMBtu	0.1 #/MMBtu	0.7 #/MMBtu
NSPS Revision[3]	85% reduction, .2 #/MMBtu floor, 1.2 #/MMBtu ceiling	99% reduction 0.03 #/MMBtu	65% reduction, and 0.5-0.8 #/MMBtu, based on coal and furnace type
Industrial			
State limits[1]	.15-9.0 (2.3) #/MMBtu	0.1-0.6 (.5) #/MMBtu	Most unregulated
NSPS Revision[3]	Unknown, perhaps 70-85% with size cut off	Unknown, perhaps 99% with size cut off	Unknown

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[1] Variablility reflects differences by location, and size. Figure in ( ) used as representative for this study.

[2] Applies to all boilers built after 1971 and over 250 MMBtu/hr .

[3] No revisions have been formally proposed. Figures reflect current anticipated range. Utility standards likely in effect in 1978 and industrial in 1980.

TABLE 1: AIR POLLUTION CONTROL REQUIREMENTS

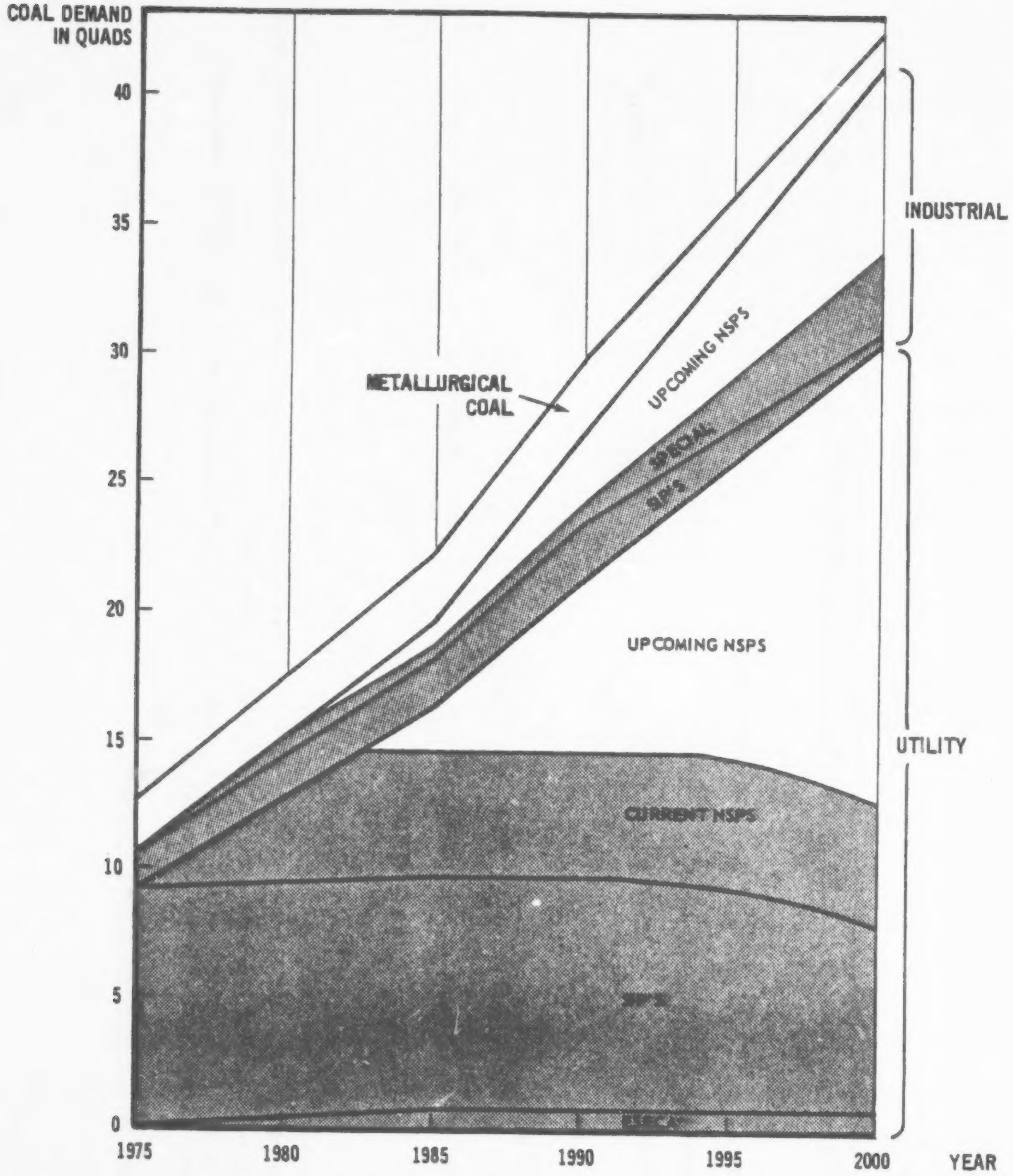

FIGURE 1: PROJECTED COAL DEMAND BY SECTOR AND APPLICABLE AIR EMMISSION LIMITS

projections are based on the "most probable" form of the National Energy Plan expected to be ratified by Congress. The shaded area represents portion of project demand falling under the existing air pollution emission limits.

The split of coal use between utilities and industry is expected to be about 80/20 in 1985 and 1990, and 75/25 in 2000. Although the upcoming revisions of utility and industrial NSPS have clear long term importance, affecting more than 50 percent of total projected coal demand in 2000, the revision will affect only 15 percent of total demand in 1985. State limitations are still important in 1990, affecting 46 percent of total non-metaalurgical coal demand. By 2000, the impact of current state limitations declines to about 25 percent of total demand.

How Coal Preparation Compares to Alternative Cleanup Technologies in the Utility and Industrial Sector.

Because coals and environmental standards vary, different approaches to coal cleanup will be required. This is particularly important because the electrical utilities are expected to spend $49 to 73 billion on pollution control devices in the next decade.[1] A significant cost saving to consumers can result from choice of the cheapest, most reliable system, expecially if it saves high-cost oil which is passed through under fuel adjustments.

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[1] Letter, John F. O'Leary, Deputy Secretary, DOE, to Douglas C. Costle, Administrator, EPA, July 6, 1978. Present value cost through 1990 depends on availability of FGD systems (90 to 100 percent) and which NSPS utility standards are finally agreed upon.

FGD will be the primary compliance method for meeting proposed sulfur New Source Performance Standards (NSPS) for new units built after 1983. Because 85 percent removal is expected to be required, physical coal preparation will be unable to meet sulfur standards alone, and must be used in combination with an FGD system.

Coal preparation and low-sulfur coal may play major roles in allowing existing coal-capable utility boilers, and units coming on-line before 1983, to meet existing SIPS and NSPS. These units, which are expected to represent 70 percent of the coal-fired utility electrical generation in 1990 and will continue to operate under the existing 1.2 #/MM Btu standard,are probably the most important area where imported oil can be saved in the next decade. In these applications, low-sulfur coal, physical coal preparation, or a combined coal preparation/FGD system is expected to be the cheapest option. An example of a combined coal cleaning/FGD system is TVA's recently announced Paradise coal cleaning plant.

Table 2 presents some results of current internal DOE study of clean-up technologies applicable for the utility and industrial sectors.

APPLICATION	UTILITY			INDUSTRIAL	
Environmental Standard	Existing SIP's	Current NSPS	Upcoming NSPS	Existing SIP's	Upcoming NSPS
1985 Coal Usage (in Quads)	9.9	4.8	1.8	2.2	1.0
1990 Coal Usage (in Quads)	9.9	4.8	6.6	3.0	2.5
Preferred Technology	Physical Cleaning Low-Sulfur Coal Medium-Sulfur Coal	Physical Cleaning Low-Sulfur Coal	Non-Regenerable FGD; Physical Cleaning & FGD; Regenerable FGD	Physical Cleaning; Low-Sulfur Coal	
Acceptable Technology		Non-Regenerable FGD; Regenerable FGD		Chemical Cleaning; SRC I; Non-Regenerable FGD; Regenerable FGD	Chemical Cleaning; SRC I; Non-Regenerable FGD; Regenerable FGD
Specialized Applications	Non-Regenerable FGD; Regenerable FGD; SRC I; Chemical Cleaning	SRC I Chemical Cleaning	SRC I (for a few coals)	SRC I Chemical Cleaning	SRC I Chemical Cleaning

TABLE 2: RANKING OF CLEANUP TECHNOLOGIES BY MARKET SEGMENT

(excluding fluidized bed combustion and low and medium BTU gas)

From the table it can be seen that with existing regulations where there is no percent sulfur emissions limitation, low-sulfur coal or physical coal cleaning will be the preferred technology. Percentage reduction requirements tend to favor flue gas desulfurization, particularly in the utility sector.

Coal consumption is expected to grow fastest in the United States industrial sector, with a tripling in coal usage from 1975 to 1990. By 1990, new industrial coal usage is expected to be approximately 100 million tons which is equivalent to saving 1.0 million bbl oil per day.

Because of the large number of users, environmental standards and types of applications (e.g., boilers, process heaters, direct heat, and metallurgical applications), evaluation of compliance techniques is complex. Existing standards, which will be in effect for all industry until 1980, are currently set by states or local governments. These state standards can usually be met most cheaply by low-sulfur or cleaned coal. In some industrial applications, however, available waste streams make FGD more economical.

In industry, reliability and cost is even more important than in utilities because large energy users that would be likely to use coal (steel, refineries, chemicals, paper) run continuously and cannot shift loads among plants as easily as an electric utility grid. With production dependent on reliable process steam, heat, and electricity, they expect a higher (95 to 98 percent) reliability. Because energy production is only a small increment of total product cost, yet could jepardize the entire industrial operation, reliability is the most important factor. Other important factors are being competitive and having flexibility in choosing to burn alternative fuels.

Coal preparation is particularly attractive because it produces a more uniform coal feed which may make boilers and combustors more reliable (approaching that of oil and gas, which are primary competitors). In many applications, coal preparation allows environmental standards to be met without FGD. This is particularly important because sludge disposal is likely to be more of a problem for urban-based industrial applications.

Because Federal industrial emission standards have not been set, it is premature to judge the value of chemical cleaning or SRC I in meeting standards. However, preliminary indications suggest very large industrial boilers (such as for cogeneration) are likely to need scrubbers and small units will probably require only physical cleaning.

DOE Organization and Funding

For the past 4 years the Federal efforts in coal preparation have been scattered. In 1975, ERDA had a number of divisions working on coal preparation, the Bureau of Mines was being encouraged and funded by EPA, and EPA was actively funding coal preparation work. In March 1976, a ERDA/Fossil Energy task force headed by C. W. Draffin reported on the status of Federal coal preparation efforts, and on June 24, 1976 the task force submitted statements of work for a proposed Fossil Energy Coal Preparation Program, the implementation of which was assigned to R. A. Corey, in what is now the Division of Fossil Fuel Processing.

When DOE was formed on October 1, 1977, the Bureau of Mines coal preparation work ($5MM) was placed in the Division of Solid Fuel Mining and Preparation, and ERDA's Advanced Research and Supporting Technology's coal preparation program ($1.2MM) was placed in the Division of Power Systems. Other coal prepration work was continued by the Division of Coal Conversion (in Fossil Energy under the Assistant Secretary for Energy Technology) and the Division of Environmental Control Technology (under the Assistant Secretary for the Environment). FY 1978 funding is shown on table 3.

Table 3

FY 1978 Federal Coal Preparation Program

DOE/Fossil Energy (From Bureau of Mines)	$5.1 Million
DOE/Fossil Energy (From ERDA)	1.2 Million
DOE/Environmental Control (From ERDA)	0.7 Million
Environmental Protection Agency (To Come to DOE in FY 1979?)	2.0 Million

To coordinate DOE efforts, a DOE Fossil Energy discussion of coal preparation was held on November 15, 1977 and George Fumich, the Program Director for Fossil Energy, requested that a program plan for coal preparation be prepared under the direction of C. W. Draffin. A draft program plan for coal preparation was submitted on January 9, 1978, but never publicly released for comment. In the recent reorganization, coal preparation, coal mining, oil, gas, and oil shale were assigned to Dick Hertzberg, Director of Fossil Fuel Extraction.

Currently, the combined Fossil Energy FY 1978 budget for coal preparation is about $7MM. The FY 1979 budget is about $7MM, with possible additional funding of $2 MM in EPA transfer funds and $3.5MM in additional Congressional authorizations. Current projects are listed in figure 2. The most significant recent decision made affecting

$1.1 MM	SOLID FUEL MINING & PRFPARATION - FIELD	
	Petrographic Studies	$0.1 MM
	Froth Floatation	.2
	HGMS Tests on Coal Samples	.2
	Equipment Studies	.1
	Instrumentation	-
	Advanced Gravity Separation	.1
	Washability Studies	.3
	Lignite Up-grading	.1
	Facility Planning	.05
$4.1 MM	SOLID FUEL MINING & PREPARATION - HEADQUARTERS	
	Bruceton Facility	2.2
	Chloronalysis (Jet Propulsion Lab)	.4
	Oil Agglomeration (Jones&Laughlin)	.75
	Fine Wastes (Dravo)	.1
	Organic Sulfur (U.of Houston)	.08
	Lignite Drying (Grand Forks ETC)	.1
	Economic Assessment	.05
	Sulfur Functional Groups (Aerospace)	.05
	Waste Impoundment Assessment (U. of Alabama)	.2
	Dry Fluidized Bed HGMS (Oak Ridge NL)	.17
	Coal Analysis (Warner Labs)(.25 USGS $)	-
$1.1 MM	POWER SYSTEMS - HEADQUARTERS	
	Oxydesulfurization (Pittsburgh ETC)	.4
	Beneficiation (Ames Laboratory)	.275
	Microwave Desulf.(via EPA) (GE)	.18
	Model for Predictions (U. of West Va.)	.037
	Effect of Minerals (U. of West Va.)	.14
	Recovery of Ultrafine Coal (Ohio St.)	.02
	Optomization of Bacterial Leaching (State Univ. of NY at Binghamton)	.02
	Precombustion Desulfurization(U. Minn.)	.077
$0.7 MM	ENVIRONMENTAL CONTROL TECHNOLOGY - HEADQUARTERS (under Assistant Secretary for Environment)	
	Trace Element Analysis (Los Alamos NL)	.225
	Trace Metals & Radioactivity (BCR)	.25
	Coal Prep for Electric Util. (Homer City)	.10
	State of Art for Coal Prep & Econ. Assessment (Argonne National Lab)	.125
$7.0 MM		

FIGURE 2: FISCAL YEAR 1978 DOE COAL PREPARATION PROGRAM

coal preparation was the funding of a $10 million Coal Preparation Test Facility in Bruceton, Pennsylvania.

Scope of Fossil Energy Coal Preparation Program

The coal preparation program is being redirected to be a driving force in the Fossil Energy Program that facilitates coal combustion, gasification, liquefaction and MHD by (1) preparing coals to reduce costs, to reduce environmental impacts, and to impove reliability of coal use and (2) helping to establish which coal characteristics are most suitable for specific applications.

The primary elements of the program include:

- Coal characterization and determination of feed requirements;
- Physical and chemical coal cleaning;
- Coal processing and handling (e.g. coal grinding, dewatering and feeding);
- Economic and market assessments.

Coal characterization focuses on the coal constituents and characteristics (ash, sulfur, Btu content, minerals, friability, caking characteristics, caking properties, etc.) that determine the best use for different coals. The program will be closely integrated with the ongoing DOE Coal Science Research Program.

The coal feed characteristics necessary for coal combustion, gasification, liquefaction, and MHD would be determined in conjuction with the appropriate program offices. The economic trade offs between extensive coal preparation and over-designed coal utilization or processing facilities would be made by the Process Design and Economics Group in the Fossil Energy Division of Systems Engineering. Particular emphasis would be paid to current combustion technology in the industrial sector, so technical problems impeding the switch to coal could be solved.

The second element, physical and chemical coal cleaning, would be a continuation of physical cleaning activities of the Bureau of Mines that have been transferred to the Fossil Energy Division of Fossil Fuel Extraction. It would also include chemical cleaning work previously funded by the Power Systems Division. Technologies to be stressed include oil agglomeration, froth flotation, advanced fine coal cleaning and advanced chemical cleaning, including oxydesulfurization. Particular attention would be paid:

- to recovering fine coal both to eliminate environment impacts of coal wastes and to increase Btu recovery;

- to developing the most cost effective way of meeting industrial and utility environmental standards (especially sulfur).

Coal processing and handling would investigate ways of handling, storing, blending, grinding, dewatering, pelletizing, transporting, and feeding coal. Primary attention would be placed on advanced grinding, dewatering, and pelletizing processes. This element of the coal preparation program would focus on coal handling problems that impede coal usage and would be done in conjunction with the Division of Fossil Fuel Processing, DOE's Assistant Secretary for Resource Applications and the Electric Power Research Institute. This activity may aid DOE's Economic Regulatory Administration by allowing fossil energy to provide technical judgement on appropriate industrial coal cleaning and handling facilities.

The economics, environmental impacts and market applications for each of these elements would be made an integral part of development and assessment. Other efforts would focus on EPA's setting of industrial environmental standards and cooperation with industry, EPA, and EPRI.

New research directions that are being pursued include the following:

Chemical cleaning - offers the potential for removal of organic sulfur (up to 40 percent) as well as increasing the removal of pyritic sulfur (up to 95 percent) frequently using high temperatures, high pressures, and chemical reagents or oxygen. DOE effort being placed on understanding coal characteristics (especially types of organic sulfur) and process conditions for removing impurities.

Oil Agglomeration - allows fine-sized coal to be recovered from water slurries and dewatered. Introduction of oil eliminates surface moisture on coal particles; occluded water between coal particles in floc can be removed by centrifuges. The product has 10 to 12 percent water (mostly inherent water) which can be direct-fired in a boiler or pelletized for shipment.

Pelletization (or Briquetting) - allows fine-sized coal to be melded into forms which are more easily transported and handled. This is part of the DOE effort to facilitate fine coal transport and usage.

High Gradient Magnetic Separation (HGMS) - Although technology has not been proven to date, use of large magnets offer potential to increase both pyritic sulfur removal and Btu recovery, at a price comparable to conventional heavy media plants, and without creating fine coal dewatering problem (oil agglomeration would be used). Dry HGMS allows sulfur to be removed in areas where water is limited.

Lignite and Subbituminous Drying and Pelletizing - improve potential for using these coals by increasing Btu content per pound, decreasing spontaneous combustion and taking out impurities such as sodium.

Trace Element Removal - coal cleaning offers potential of removing some heavy metals before combustion.

Automation - development of operational ash, sulfur, and moisture meters that could be installed to improve Btu recovery and product quality.

In DOE headquarters the primary Fossil Energy people involved in coal preparation are Bill Warnke, Cyril Draffin, and Wayne McCurdy.

DOE's field organizations include the 50 member coal preparation group headed by Al Deurbrouck, which is divided into two groups. The Coal Preparation Laboratory in Bruceton includes 25 full time and eight part-time people while the Coal Preparation Analysis Group in Pittsburgh has 15 full-time and two part-time people. In addition, parts of the Pittsburgh Energy Technology Center (PETC) are actively involved in chemical coal cleaning (under Jim Gray) and environmental work (under Bill Peters). Ames Laboratory is actively involved in physical and chemical cleaning and Argonne National Laboratory is involved in environmental assessments.

Scope of Coal Preparation Program under Assistant Secretary for Environment

The Assistant Secretary for Environment (ASEV) has the responsibility to access the environmental, health, and safety aspects of DOE energy technologies. To meet this responsibility, the Assistant Secretary reviews the environmental, health, and safety aspects of energy technology RD&D in the context of environmental policies, and conducts research and development to meet the needs of DOE programs for new information and data in the environmental, health, and safety area. The primary people in headquarters are Myron Gottleib and Charles Grua.

Programs currently underway are directed at mitigating the impact of waste material from coal preparation plants. An example is a project to determine the reclamation techniques for waste banks in a cooperative effort with state and local governments. Ecological effects and long-term stability of reclaimed land will be assessed over a multiyear period. Other studies address the potential environmental impact of leachates from both unreclaimed waste banks and coal storage piles, and the control technology requirements to mitigate these impacts. The fate of trace and minor elements in the overall coal utilization cycle is being assessed in a laboratory study of physical coal cleaning utilizing coals from various regions.

A major study directed at the environmental implications of generating electricity from coal is being conducted at Argonne National laboratory. This study is expected to provide an assessment of the current state-of-the-art of coal preparation and the tradeoffs through the fuel cycle of benefits and costs. Also, through a cooperative effort with EPA, an assessment of the control technology status is being made of the Homer City Coal Cleaning Demonstration Plant.

Issues Facing DOE and Industry

Two primary issues face DOE and industry: (1) whether coal preparation will be of significant value in allowing technologies to use coal in an environmental acceptable way, and; (2) whether private industry will develop advanced coal cleanup technologies in a timely manner.

Because the only real alternatives to clean coal combustion are burning oil or gas or using nuclear power, it is necessary to have reliable, reasonably economic, commercial cleanup systems available.

The general strategic options available to DOE in the coal cleaning area include any or all of the following:

A. Industrial and Utility Tradeoff Studies

- To facilitate enforcement of Federal and state legislation
- To determine best way of meeting different environmental standards
- To identify R&D needs
- To assess validity of requested cost and environmental exemptions under the coal conversion provisions of the National Energy Act
- To independently comment on EPA regulations
- To recommend new legislation

B. Applied Research and Development

- To support reliable compliance with existing and anticipated environmental standards
- To support EPA by developing best available control technologies, especially for nonattainment areas
- To make up for lack of industrial R&D caused by potential sudden obsolescene with changing environmental regulations
- To reduce costs of using coal
- To overcome industry's hesitency to develop improved control technologies that they will be forced to install at additional cost

C. Commercial Demonstration

- Decrease technical uncertainty to ascertain need for exemptions
- Develop data to allow EPA to set more realistic standards

Further examination of industry's intentions and likely performance appears needed in planning both R&D and demonstration projects because we do not yet have a clear picture as to why vendors and coal users will not develop technology themselves.

Joint planning by industry and Government will be essential to develop coal cleanup technologies that protect the environment while assuring reliability and cost-competitiveness of using coal.

The Department of Energy is interested in your factual appraisal of specific areas in (1) cleaning, dewatering, or handling coal or lignite, (2) disposing of coal preparation wastes, or (3) operating coal preparation facilities where there are significant process improvements needed. In making those suggestions, a documented discussion is needed of what private industry is doing and how (if at all) the Federal Government can be of specific assistance.

OVERVIEW OF EPRI COAL CLEANING PROGRAMS

Kenneth Clifford and Shelton Ehrlich
Electric Power Research Institute
Palo Alto, California

No abstract or paper available.

AN INTEGRATED ASSESSMENT OF COAL TECHNOLOGIES

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ABSTRACT

The Coal Technology Assessment (CTA) is a part of EPA's overall Integrated Technology Assessment (ITA) program. ITA was launched to "identify environmentally, socially, and economically acceptable (energy development) alternatives". The CTA study will try to anticipate what a given coal-based energy-technology mix might mean to our society and to outline policy options that can prepare us for that projected future. Two basic questions concern the level of coal-derived energy desirable in the U.S. over the next half century and the social, economic, environmental, and institutional impacts of different coal technologies that might be employed to meet this level. The product of the study is intended for use by policymakers at all levels of government and in the private sector, not just EPA.

The study process involves six major modules: issue identification--projected problems and conflicts; scenario development--descriptions of different possible states of future society; projected technology mixes within these scenarios; measurement of impacts of coal-based energy development; development of policy options; and communication of the findings. The bottom line of the study is policy options and the key element is public participation. The policy options will be intended to avoid or mitigate undesirable impacts--environmental, social, or economic--of coal-based energy technology or to take advantage of opportunities that may be discovered. Policy options will fall into two major categories--legal/institutional and technological. Public participation throughout the process by which these policy options are developed is critical. This is being accomplished through such devices as interested party forums in different parts of the country, a newsletter encouraging feedback, and involvement of a National Technical Advisory Council.

Traditionally, energy/environment research programs in the U.S. have been concerned primarily with the health and ecological impact of new energy plants and technology. In December, 1973, Dr. Dixie Lee Ray, then Chairman of the U.S. Atomic Energy Commission submitted a report to President Nixon titled, The Nation's Energy Future. This propelled interest in a broader-based look at the effects of energy technology and provided the impetus for a Government interagency program on energy and the environment. As a result, two interagency panels -- one dealing with control technology development, the other with environmental effects research -- developed Dr. Ray's suggested program in greater detail.

From the reports of these panels, often referred to as the "Gage Report" and the "King-Muir Report", the Office of Management and Budget established an interagency task force on the "Health and Environmental Effects of Energy Use". This task force was to (a) examine ongoing federal research in the energy/environment field and (b) recommend an allocation of research funds for a more effective research program.

A major conclusion of the energy/environment task force was that the social and economic consequences of alternative energy and environmental policies had to be considered along with the more traditional health and environmental impacts. The King-Muir report recommended the formation of a research program to identify "environmentally, socially, and economically acceptable (energy development) alternatives". As a result, the Environmental Protection Agency (EPA) launched the Integrated Technology Assessment (ITA) program.

Traditional EPA environmental research programs had followed the same trend noted in the introduction. They had been "waste stream" oriented, confining the environmental analysis to direct effects of pollutant emissions and discharges from industrial facilities. Adequate attention frequently had not been given to "nonpollutant" effects such as noise, land use, employment, community services, and esthetics. The Gage report reoriented this program by calling for a series of "environmental assessments" (EA's) designed to go much further in utilizing chemical and biological analysis, as well as existing health/ecological effects data, to assess the impacts of industrial discharges on air, water, and land. The report also recommended attention be given to nonpollutant effects, i.e., social and economic. Six environmental assessments (EA's) are now under way for high- and low-Btu gasification, coal liquefaction, fluidized-bed combustion, conventional combustion, coal cleaning, the subject of this Conference.

Further, EPA is currently sponsoring three technology assessments on energy: the Western Energy Study under the direction of the University of Oklahoma's Science and Public Policy Program, the Ohio River Basin Energy Study (ORBES) being undertaken by a group of seven midwest universities, and the Coal Technology Assessment study being reviewed here and being conducted by Battelle's Columbus Laboratories and the University of Michigan's Program in Technology Assessment.

Technology Assessment (TA) is a class of policy studies directed tc examine the broadest social implications of the introduction of a new technology or the expansion or extension of an existing technology. It is intended to provide the decision-maker with useful advice and guidance on policies, programs, plans, and alternative actions. Since there exists no "science" of TA, the specific techniques employed for any given technology assessment are subject to considerable debate and variation. However, with some variation, it is generally agreed that most technology assessments include at least these generic elements:

- Definition of the Problem
- Description of Alternative Technologies
- Identification of Biophysical and Socioeconomic Impacts
- Evaluation of Impacts
- Characterization of the Decision-Making Process
- Identification and Evaluation of Policy Alternatives
- Involvement of Interested Parties, i.e., those who have a direct stake in possible impacts
- Utilization of Scenarios
- Communication of Results.

The Coal Technology Assessment will involve each of these elements. The general framework in which are they being included and the major objectives of the CTA are as follows:

- Assess environmental, social, economic, and energy impacts of coal-based energy technologies, supply systems, and end use.
- Identify, analyze, and compare technological and institutional methods of avoiding or mitigating undesirable consequences of coal-based energy development.
- Identify, analyze, and compare alternative policies and implementation strategies for coal-based energy development.

In short, the study will try to anticipate what a given coal-based energy technology mix might mean to our society and outline options that can prepare use for that future.

To provide "settings" for the study three "scenarios" representing divergent, but plausible, concepts of our society to the year 2030 have been created. These scenarios are described in narrative form and structured like mini-dramas. They contain a number of assumptions about the future covering the state of technology, government institutions, population distribution, economic needs, and many other factors. Included are assumptions about emerging social value systems that can affect energy -- and therefore coal -- demand.

Based on these assumptions about future states of society, we can project various levels of demand for coal-based energy. The next step is to determine what levels, mixes, and timing of the development and deployment of coal-based energy technologies will meet these various demand levels. A number of plausible combinations are being examined. The study will identify and evaluate the social, economic, environmental, and energy consequences (impacts) resulting from the various technology mixes in order to compare the "trade-offs" between them.

The approach being taken in this assessment might be described as a series of snapshots in various time frames. We begin with 1978, which is really the data base used for information. Then we look at a snapshot in three different time periods or "slices": 1985, 2000, and 2030, simply because there is not the time or resources to look at all of the years between 1978 and 2030.

Who are the potential users of this study? At this point we don't really know what user groups are going to use the product of the study most effectively. It might be an environmentalist group; it might be a local government; it might be an agency or some other federal department that is not so obvious as the EPA and the Department of Energy. It might be a state government like Massachusetts rather than one in the Rocky Mountain region. Therefore, the targets, for the products of this study are viewed as multiple targets, meaning that we do not look upon EPA as the only user of this study.

The major products envisioned for the Coal Technology Assessment Program include a comparative assessment of the social, economic, and environmental consequences of technology in two time frames -- the present to 2000, and 2000 to 2030. As mentioned earlier, a bottom line of the study is policy options, meaning what actions among alternatives can be taken to avoid or mitigate undesirable consequences of coal development. As in all coal development research efforts, we must identify in a long time frame, future research and development needs. There are special features of the CTA program that are not present in all studies conducted by DPA, or by other government agencies. For example, we have a National Technical Advisory Committee composed of eight people representing a variety of agencies, institutions, and disciplines. The study is sponsoring interested party forums such as one held recently at Keystone, Colorado. The initial interested party forum was held at Airlie House, Virginia, in early March. In June we assembled a forum of experts in Washington, D.C. to identify and prioritize issues from an initial list of over 200 issues. We feel that communications and public involvement are critical to this study.

There are a number of modules in the TA process such as the issues module, policies module, impacts module, scenario module, technology module, and communication module. By putting these together the flow in the process of the Coal Technology Assessment is characterized. First we must identify important specific issues because we do not have the resources to examine the whole Universe. The issues determine the tools to be used in the study analyses. There are several different types such as broad issues which really provide the context for the study. There are regional issues and environmentally specific issues. For example, the CTA is intended to provide a basis for answering two broad questions: (1) What level of coal-derived energy use is most desirable in the U.S. over the next half-century (1978-2030)? and (2) Does it matter, i.e., from the standpoint of the comparative costs and benefits of social, economic, environmental, and institutional impacts, which coal technologies are deployed in meeting this level of energy use? The conclusions of this study are intended for a primary audience of public and private decision-makers who must act regarding questions such as these over, perhaps, the next ten years. It is clear that these decisions will have major implications for the U.S. as it moves through the remainder of this century and into the 21st.

Examples of major issues would certainly include the long-term build-up of CO_2 in the atmosphere as a global issue; the prevention of significant deterioration of air quality is a very significant issue in the Rocky Mountain egion. How we control toxic substances, including the hazardous substances that may be discharged from coal is a critical issue. Water supply will certainly be addressed as an issue. Another example of an issue is how do we resolve, or can we, the jurisdictional conflicts between federal, state, and local governments, and in the West we must include Indian tribes.

The next module in the assessment process is the structuring of scenarios. We have so far in the study structured only three national scenarios, presently identified as A, B, and C. As an example, we will make assumptions on GNP, on quads of energy demand and quads of coal demand for each of the scenarios.

The next module deals with the selection of technology mixes; the level of coal development that will utilize these technologies are predetermined by the assumptions in the scenarios. If we have a business-as-usual scenario, the level of coal development will obviously be higher than if we have a conservation scenario. Having determined the level of development and the rate within the time frames that the technologies on come on-stream, we can also look at the deployment of technologies on a regional basis. Thus we will also be examining development according to the assumptions in the scenario, the rate the technologies are commercialized, and the regions in which they are deployed. A coal trajectory is composed of various modules; an extraction module, processing module, transportation module, and so forth. When we combine these modules together, there is an almost infinite variety of combinations identified as a coal trajectory. A combination of trajectories identifies a technology mix.

The next assessment module is the characterization of technologies. We have structured the scenarios, and out of the scenarios we have selected a technology mix to meet certain coal demands. We must characterize the selected technologies in terms of what actions are taking place that have an effect on the environment. A few examples of the manner in which technologies can be characterized are: How many acres of land are required? How many feet of water will be needed? How many employees are needed in the labor pool? How much capital for construction in the plants? and so forth. There are some obvious outputs in terms of the water and solid waste, health and disease implications. For example, possible long-range effects of cancer in the general population; toxic discharges into the air. There are numerous such factors which can be studied numerically. However, the CTA must consider many characterizations such as aesthetics or the quality of life to which we cannot conveniently put numbers.

Having characterized the technologies, we estimate the impacts in a number of ways. What is their magnitude? Are we characterizing a large impact or a very small one of limited duration? How is the impact distributed? Is it specifically regional, statewide, or national, or perhaps international? What is the political perspective? Is the impact considered by identifiable groups of people to be important to them? Will it last only during the construction of the project and then be gone? Or will it be a long-term effect like discharges of radiation? And when will it occur? Today, next month, 5 years from now, or, possibly like cancer, 20 to 30 years in the future?

The next step in the TA methodology is to evaluate the impacts. The evaluation criteria serve as a screen for selecting the impacts that we are going to evaluate. There are hundreds of impacts that the study could examine. We can't look at the whole Universe, so we have to have some criteria for selecting the impacts that we feel are of most critical importance both politically and scientifically to whomever we are dealing with. What is the geographic perspective for the CTA? Are we dealing with a unique resource? Do we have the ability to assess the impact? These are some of the key criteria used for impact evaluation.

The next module of the process is the identification of policy options. The purpose of policy analysis is to identify the bases for policies that will avoid or mitigate undesirable environmental, social, or economic consequences of the deployment of coal-based energy technologies. Or, hopefully, to take advantage of opportunities that may be discovered. Because impacts can be both positive and negative, two basic types of policies must be identified: legal and institutional. This really goes to the questions, do we need a new law? A state law or a federal law? Do we need a new government organization such as a regional council? Or a new type of authority to deal with particular problems? The technology mix policies are concerned with such considerations as scrubbers, precipitators, boiler modification, research and development on new coal-cleaning processes, and similar engineering-oriented applications. We also must look at policies that are both technological and legal/instutional. The policies are evaluated in two different perspectives: their scientific perspective -- that is, policies that address issues that have scientific data bases, and policies that address issues that are sociological and political in nature. Policy makers must address problems and issues as they are perceived by the public in the political process. Those problems and issues may or may not have a good scientific data base. Then we review and critique. And in our review and critique we use our technical advisory committee, those who attend the public forums, panels of experts, and, of course, the Program Core Team and EPA staff. The review process is very critical to the study. Finally, the findings must be communicated. We consider communications extremely important and must use a variety of media: newsletters, forums, written reports, slide or film presentations.

Having reviewed the process, to use an example, let's take the issue of acid rain. There are many dimensions of this issue. How it affects the productivity of the land: does it mainly degrade fishery or wild life habitat or other parts of the ecosystem? It might result in climatic changes, for example. It is not possible to look at all dimensions; however, we can select key ones. Using the example of acid rain, the issue must be examined within the context of a scenario. Scenario C, or what we call business-as-usual will be used. The region identified is the intermountain West. The year is 2000. We're looking at one characterization: the emission of SO_2. Under Scenario C, in the intermountain West, in the year 2000, we project an energy demand and determine how much energy of that demand will be provided by other sources of energy. A projection is then developed for coal-based energy in that region and the technical mixes selected. The question then becomes, What technologies will be required to provide eight quads of energy in the upper midwest region in the year 2000? Can we come up with this particular type of mix? We characterize these technologies that we have selected as being needed. In this case, we will characterize it only for SO_2 and our characterization is that the total emissions to the region, or as a total burden, will be 9-1/2 million tons of SO_2. Then we evaluate the impacts. We've only selected one type of impact: the land impact of acid rain, and one category of impact. Of course, there are many impacts on acid rain on land: those listed are a few of the more important ones.

THE MAIN TRENDS OF WORKS ON ENVIRONMENTAL PROTECTION AGAINST THE INFLUENCE OF COAL-PREPARATION PLANTS IN THE USSR

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I. Ch. Nekhoroshy, and I. E. Cherevko
USSR Ministry of Coal Industry
Soviet Union

Coal industry is the basis of the Soviet power fuel industry. In 1977 coal production in the Soviet Union amounted to 715.700 tons, by 1980 it will be 790.000.000 - 810.000.000 tons.

It is envisaged that further development of not only Donetsk coal basin but such important coal basins as Kusbass,Ekibastuz, Kansk-Achinsk and South Yakutsk coal fields.

Under the existing conditions of intensive scientific and technical progress and rapid growth of industry the problem of rational use and reproduction of natural resources in fuel-power complex of the country has become one of the most important state problems, solving of which is closely connected with health protection of present and future generations of people and their wellbeing.

High rate of coal industry development and demands for high quality fuel have caused a considerable growth of coal preparation output in the last few years.

In 1977 nearly 345 800 000 tons of coal were cleaned.

The development of coal preparation is based on recent achievements of science and industry, on building of new large-scale plants and reconstruction of existing plants.

At preparation plants use is made of modern methods and high-capacity equipment which provides simple operation and technological efficiency of coal preparation. Progressive methods of cleaning,heavy media separation , jigging and flotation are widely used at coal preparation plants.Great attention is paid to the use of closed water-slurry circuits and purification of stack gases exhausted from dryers and fans to sanitory standards. At a number of preparation plants wastes are used as raw materials for the construction industry. At a preparation plant in Moscow region coal basin non-refuse technology is used.

In accordance with coal preparation development main trends in environmental protection against the harmful effect of coal preparation plants are:

- protection of water resources from impurities;
- preventing of airborn pollution;
- complex utilization of mineral matter and utilization of wastes;
- reduction of technological losses in the process of coal preparation.

Closed water-slurry circuits,
dewatering of slurry and flotation tailings.

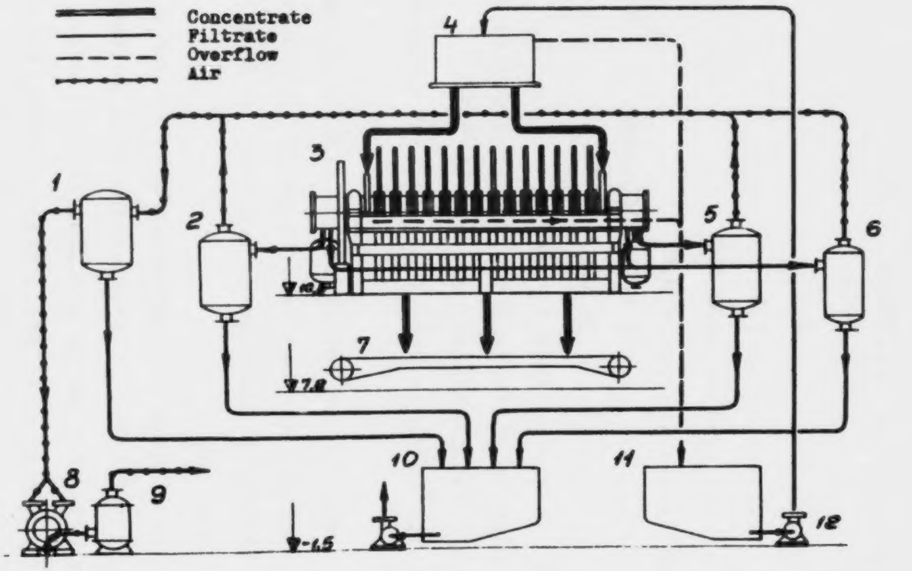
Coal preparation plants of the Soviet Union are processing a wide range of coals at various stage of metamorphism and it characterises the features of technology and equipment and at the same time it defines physicochemical content of industrial water.

The improvement of technological circuits envisages the creation of non-refuse technology. For this purpose it is necessary to solve a number of problems:

- the use of flotation for recovery or reclaimed water;
- the use of equipment and methods for dewatering of flotation tailings;
- the use of closed water circuits at preparation plants.

The experience of a great number of coal praparation plants using one-stage water-slurry circuit with the recovery of washing water showed the possibility of reduction water-slurry volumes from 10-12m^3/h to 3-4m^3/h per ton of cleaned coal and drain of maximum quantity of slimy particles.

In technological circuits of coal preparation plants flotation is the initial operation for water recovery previous to dewatering. The improvement of dewatering in the USSR is gained by means of increasing filtering area from 80 to 250-300m^2 by improvement of filtration technology, the use of thickened pulp and by the use of physicochemical means of intensification. A new disc vacuum-filter DU-250-3,75 (Fig.I) came into operation at a Kusbass coal



Concentrate
Filtrate
Overflow
Air
1
2
3
4
5
6
7
8
9
10
11
12
7,8
-1,5

Fig.1. Disc vacuum filter DU-250-3,75

1.trap; 2.receiver; 3.disc filter; 4.pulp drain; 5.receiver; 6.receiver; 7.conveyer; 8.pump; 9. sump; 10.filtrate tank; 11.moisture trap; 12.pump.

preparation plant.It has the following specification

- filtering area,m^2	250
- disc diameter, m	3,75
- number of discs	I4
- number of sections in a disc	I6
- frequency of rotation,rpm	
discs	0,32-I,2
stirrer	30;50
- capacity, kvt	
drive of discs	8,5
drive of stirrer	7,5
- vacuum, mm	500-600
- blowing pressure, kgs/cm^2	to 0,6
-dimentions, mm	9 200x4 380x4540
-mass, kg	35 000

Moisture of cake is 28,9%, loss of solids is 20kg/m^3.

The use of such filters helps to increase the specific capacity of filters in 2-2,5 times and to reduce moisture content of cake by 2-3%.

The use of hydrophobic reagents improves the capacity of filters and specifications of the process.

For intensification of thickening and dewatering synthetic polymeric flocculants are employed. They are employed in bowl centrifuge NOGSh-I350 with the capacity up to 250m^3/h and in thickeners with the capacity up to 300m^3/h, which are used prior to vacuum filters, etc.

In recent years polymeric flocculant polyethylenemin has found a wide use in coal preparation. It is highly efficient in combination with polyacrylamide.

The new trend in this field is the use of granular flocculants.

As a rule closed water circuits of coal preparation plants include sewage treatment structures.

For compensation of technological water losses coal preparation plants use mine water. In I975 the volume of reclaimed waters at coal preparation plants was accounted to 847 500 000m^3, and in I980 this figure will increase up to I I20 000 000m^3.

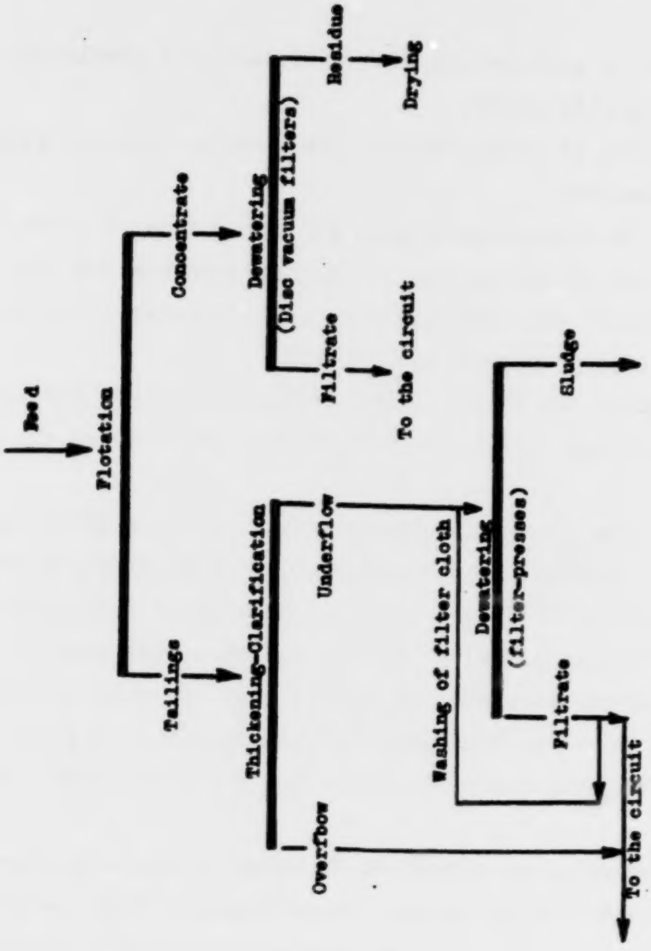

Feed
Flotation
Concentrate
Dewatering
(Disc vacuum filters)
Residue
Drying
Filtrate
To the circuit
Tailings
Thickening-Clarification
Underflow
Overflow
Washing of filter cloth
Dewatering
(filter-presses)
Sludge
Filtrate
To the circuit

Fig.2 Process flow diagram of flotation tailings dewatering

Special filtration sections equiped with cell filter-presses providing the closing of water-slurry circuit inside of plant building are used for improving the flotation tailings transportability characteristics. (Fig.2).

Here are the most prominant characteristics of new water-slurry circuits:

I. Flotation is used as the most efficient and simple method of water purification;

2. Conditioning of pulp provides its constant density without water dilution,

3. Reducing of operations number and the volume of slime water, elimination of the escess slime circulation and the shortening of the time of slime stay in water, help to reduce slime formation by 30-45%.

Introduction of new water-slurry circuits provides the reduction of solids content in recycling water (to30-80g/l) and to increase the apparatus efficiency.

For the purpose of reducing industrial recycling water impurities the investigation of reagent regimes and the use of reagents in the process of flotation is carried out with regard to their efficiency and residue concentration.

Frothing and foam removing alcohol reagents were usually doped into flotation machine chambers. Now at some plants they are used at the initial stage of the process and it helps to minimize the consumption of appolar reagent in I,5 times. It also improves froth structure and provides normal operation of flotation machine.

In recent years great attention is payed to the collection and purification of rain and thawing waters. Investigations were carried out to determine contaminants of spontaneous surface water run-offs from theterritory of coal preparation plants to water reservoirs. On the example of a number of coal preparation plants it had been setteled that surface rain water run-offs are contaminated with suspended matter which contain rock and magnetite particles, oils and petroleum products. For utilization of water run-offs it is necessary to use mechanical and physicochemical purification. At present there is a number of preparation plants using purified surface water run-offs in their technological circuits. It is supposed that this experience will be shared within the industry. It is necessary to emphasize that investigation of methods for surfuce water run-offs purification were carried out with regard to climatic conditions and location of coal preparation plants.

Control for the operation of industrial water treatment plants is carried out in accordance with the existing departmental regulations. Commissioning of these plants is exercised by State Commission including the representatives of Sanitary Inspection and Water Utilization and Protection Agencies.

Purification of stack gases exhausted from dryers of aspiration systems and other sources.

Operationof coal preparation plants results in atmosphere contamination. The sources of contamination are: emissions of dryers, emissions of boilers, emissions of industry blowers, haulage and transportation stations, stockpiling, dried mud-settling ponds, etc.

Industrial emissions of coal preparation plants contaminate the atmosphere by the following ingredients: coal dust, sulphur dioxide, carbon monoxide and nitrogen oxide. In this case emissions industrial blowers contaminate the atmosphere only by coal dust. The main trend of scientific investigatiobs in the field of atmosphere protection from harmful emissions of coal preparation plants is the development and introduction of efficient ways for reducing the absolute quantity of harmful emissions with concentration stipulated by legislation on environment protection(Table I).

Alongside with blowers and boilers, dryers are the source of air pollution. Dryers blow out into the atmosphere up to 53 000 000 000m^3 of stack gases per year which contain residual dust, nitrogen oxide, etc.

With a view to a wide use of mechanized coal winning the use of new technology for coal getting, the development of new methods for fine coal flotation and location of coal preparation plants in the districts with severe climatic conditions the volume of dryed coal will increase from 45 700 000 tons by I977 to 69 300 000tons by I980.

TABLE I.

Limit concentrations of contaminants in atmosphere of populated localities stipulated by legislation on environment protection.

SUBSTANCES	Limit concentrations, mg/m^3	
	Maximum single concentration	:Average concentration : per 24 hours
Coal dust	0,5	-
Sulphur dioxide	0,5	0,05
Hydrogen sulphide	0,008	0,008
Carbon sulphide	0,03	0,005
Nitrogen oxide	0,085	0,085
Carbon monoxide	3,0	I,0

At present investigations aimed at the search of the most effective flowsheets and methods of dryers dust trapping have been completed.The following measures are provided for achieving the legislation standards of gas purification:

- introduction of three-stage system for gas stack purification;
- use of highly efficieny unloaders for the complete separation of dried coal from gasses;
- installation of battery cyclones with the efficiency up to 98-99% and apparatus for wet trapping with the efficiency to 99,5-99,9%;
- utilization of recovered products and conducting of a continuous control for the intensity of gas emissions;
- effective control for technology with regard to stack gases dustiness;
- search for more effective methods to obtain drying agent or utilization of fuel with low ash content. Three-stage flowsheets

comprising effective devices for dry and wet purification of stack gases exhaused from dryers are now introduced at coal preparation plants.Flowsheets for purification of stack gases is shown in fig.3

As a rule, MPR wet dusters (Fig.4) for purification of stack gases exhausted from drying sections are placed at the third stage. Specifications for dusters are shown in table 2.

TABLE 2.

Type	MPR-75	MPR-I00
Capacity, m^3/h	75 000	I00 000 - I25 000
Water consumption, g/m^3	not less than 50	-
Cyclone diameter, mm	2500	3000
Aerodynamic drag, kg/m^2	I50	-
Dimentions, mm		
length	50I5	6500
height	2900	3I60
width	10380	I2950
Efficiency, %	99	to 99
Mass, kg	4950	6500

In the nearest future all drying sections will be equiped with such devices.

Aspiration blowers at all coal preparation plants blow out nearly 88 000 000 000 m^3 per year. One or two stages of dusters are used for cleaning of suction air. When dustiness of cleaning air achieves 3 g/m^3 two-stage floasheets for dust trapping are used.

One more source of air pollution is coal unloading junction at car dumpers. In recent years system of suction and dust trapping is introduced at a number of car dampers. (Fig. 5).

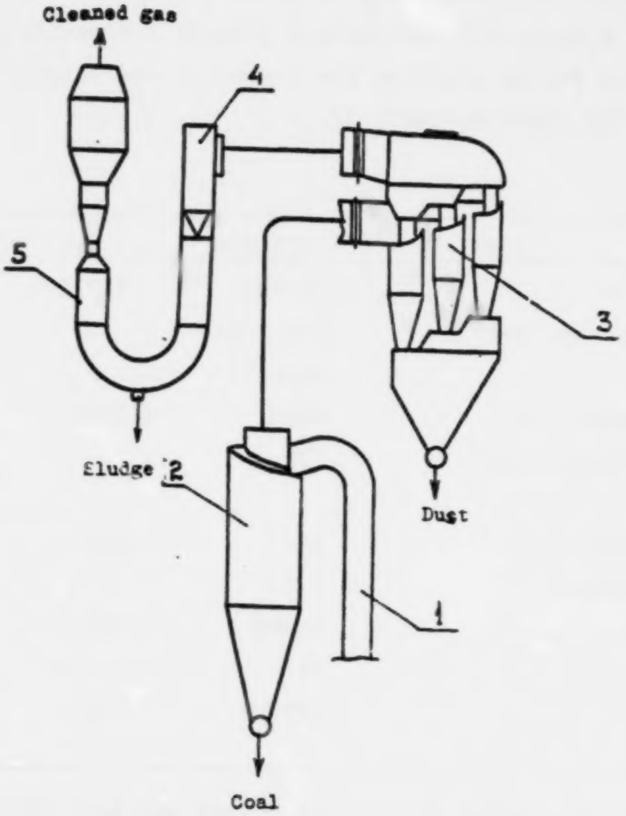

Cleaned gas
4
5
3
Sludge
2
Dust
1
Coal

Fig.3. Scheme of stock gases cleaning
1.stock gases
2.discharge gravitation chamber
3.battery cyclone
4.wet dust trap
5.duct

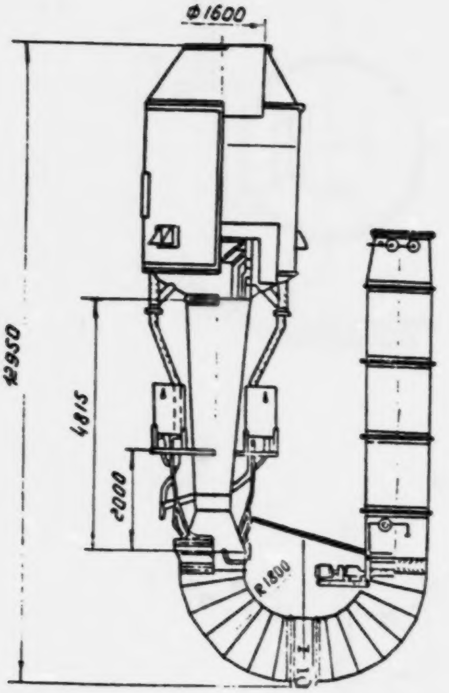

Φ1600
12950
4815
2000
R1800

Fig.4 MPR-100 wet duster

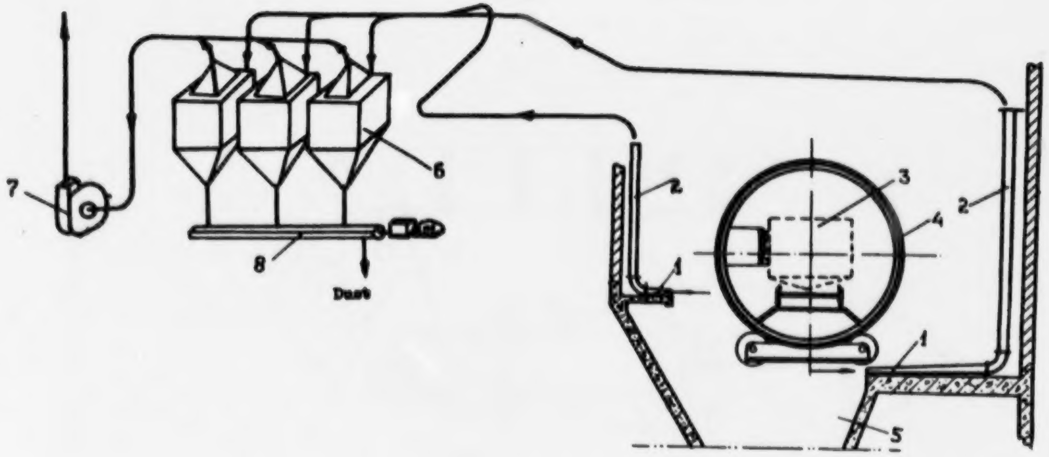

7
6
8
Dust
2
1
3
4
2
1
5

Fig. 5 Suction scheme of car dumper.
1. Air receivers. 2. Air ducts
3. Car. 4. Car dumper. 5. Coal stockpile.
6. Battery, cyclones. 7. Blower

At a number of new plants closed bins of silo type are built in order to prevent coal dust blowing out. It gives the opportunity to minimize land area for coal storages.

Monitoring of dust concentrations in stack gases is gained by taking stack gas samples by means of suction tube with filter inside (Fig.6).

Except direct monitoring a method of predicting solids concentration in ground layer of air is used at coal preparation plants.

The predicted maximum dust concentration (Cm,mg/m^3) with regard for emissions is calculated according to the formula:

$$Cm=\frac{AMPm}{H^2\ V\ T} \qquad \text{where,}$$

A - coefficient depending on temperature stratafication of atmosphere, sec $^{2/3}$ grad $^{1/3}$;

M - quantity of impurities exhausted into the atmosphere, g/sec;

F - dimensionless coefficient accounting for sedimentation rate of impurities in atmosphere;

m - dimensionless coefficient accounting for conditions of emissions dicharge;

H - hight of exhaust stack over earth level, m;

V - volume of stack gases, m^3/sec;

T - difference of stack gas temperature and the temperature of atmospheric air, C°.

The results of calculations made according to the above mentioned formula are similar to the results of direct dust monitoring in ground layer of air. Besides some coefficients should be specified more accurate with regard for various climatic areas.

Complex utilization of mineral matter and utilization of wastes.

Coal preparation wastes are the source of atmosphere pollution. Besides they occupy considerable areas good for agriculture and construction. The amount of wastes at coal preparation plants sponsored by Ministry of the

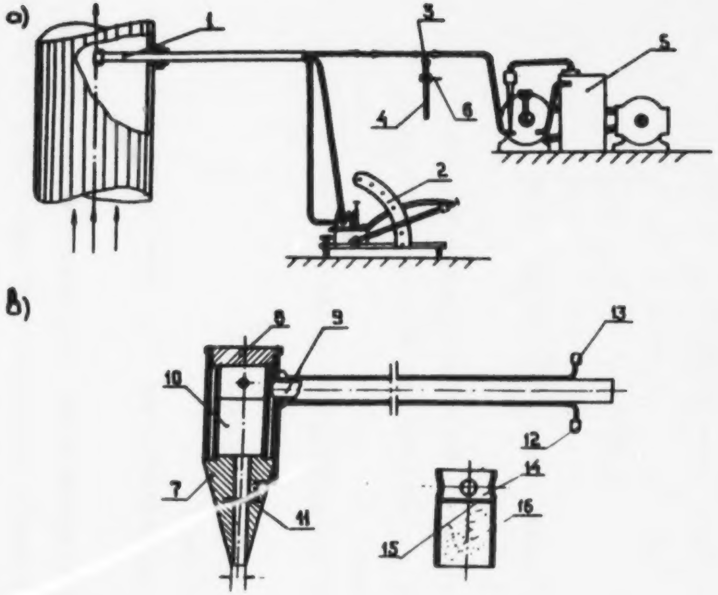


Fig.6. Installation for stock gas sampling.
a) Installation
b) Dust collecting tube
1. dust collecting tube; 2. micromanometer; 3. T-piece joint; 4. rubber rube; 5. fast; 6. fastener; 7. casing; 8. cover; 9. suction tube; 10. cartridge; 11. aperture for measuring static pressure; 12. sleeve; 13. sleeve; 14. grid; 15. filtering paper; 16. cotton wool.

Coal Industry of the USSR reached 46 000 000 tons. The share of flotation wastes with high ash content accounted for 7 200 000 tons.(70%).

It is known that wastes of coal preparation plants are stable in their elementary and granulometric composition. They can be successfully utilized in various branches of industry. The accomplished research and development investigations proved that the major quantity of wastes had been found suitable as an effective raw material.

Due to possible utilization wastes can be classified as follows:

- for production of construction materials (inert concrete aggragate, effective construction ceramics, cementing material, etc.);
- for construction of roads, earthwork (crushed stone, ballasting, etc.);
- for production of sulphur compounds.

At present I0 000 000 tons of wastes per year are used in construction and chemical industry, in tracklaying and recultivation of land.

The designing of a new pilot plant with the capacity up to I00 000 m^3 of agglopоrite per year has been started. The pilop plant will treat wastes from a coal preparation plant.

The investigations for the utilization of wastes from Donetsk and Pechora coal basins showed that one of the main factors for mass quality adjusting is the change of raw material size that causes the change of production quality. The top size is less than Imm. So flotation wastes can be efficiently used for the production of ceramic construction materials.

The research Institutes have developed the recommendations for transportation of flotation wastes from coal preparation plants of Donetsk coal basin to brick plants. Wastes should be used as an admixture in brick production.

In I977 I60 ooo tons of flotation wastes were utilized at brick plants. Flotation wastes can be used for the production of inert concrete aggragates.

The preliminary work for the construction of industrial plant in Donetsk coal basin is successfully completed. The technology for granulation and roasting of wastes is promissing.

The work is started on the utilization of coal preparation wastes as crushed stone, filled-up ground, etc. Coal preparation wastes were used for the making an experimental track. The utilization of shale wastes is of particular importance. Shale wastes are widely used in highway engineering at the North-West districts of the USSR.

Wastes from coal preparation plants of Donetsk, Pechora, Kizel coal basins are of high sulphur content which can be the source of atmosphere pollution (Table 3).

TABLE 3

Sulphur content in Donbass coal preparation plants wastes

	The range of index changing %	Indexes of the most coal preparation plants (80%)	average
Total sulphur	0,7-7,I	1,5-6,6	4,I0
Pyritic sulphur	0,63-6,80	I,3-6,5	3,82
Sulphate	0 - 0,20	0,03-0,I0	0, 07
Organic sulphur	0 - 0,77	0,03-0,40	0,2I

Investigations showed that I2% of sulphur containing in wastes turns into sulphur dioxide and 9% turns into hydrogen sulphide.

Monitoring of noxious gases concentrations resulted in defining the regularity of sulphur compounds scattering in the atmosphere at various distances from refuse pilling.

The investigations showed the possibility of changing the existing system of refuse pilling. At present measures are taken to prevent spontaneous ignition of refuse pilling. It is, for example, the construction of flat piles. Keeping strictly to the established measures of preventive treatment it is possible to avoid self-ignition and emission of noxious compounds into the atmosphere.

Great attention is paid to the stockpilling of wastes in worked out space. As investigations showed stockpilling of flotation refuse in worked out space of coal mines will allow to avoid a construction of ponds.

However allocation of flotation wastes in worked out space causes the contamination of aquifer levels with flotation reagents. Investigations of various methods of refuse cleaning showed that nitriging is the most effective method of cleaning.

Testing of wastes cleaning and stockpilling complex is at the stage of control. Utilization of flotation wastes for preventing self-ignition of stockpilling is of great interest and Soviet engineers have developed the research programme for investigation of this trend.

Sulphur is a noxious ingredient so the development and introduction of efficient methods for reducing sulphur content in cleaned coals and utilization of wastes with high sulphur content is of great importance for environment protection.

Usually standards for ash and sulphur content in coals (concentrate) have been fixed according to specifications of each plant.

The top ash content of steam coals depends on their consumption, that is, burning of steam coal in stationary boilers, brick roasting, municipal needs, etc. For providing sulphur reduction of steam coal and utilization of wastes research and development institutes have carried out investigations on the utilization of sulphur containing wastes.

At steam electric stations of the USSR use is made of coals with low sulphur content (0,2-2%). Only small part of coals with high sulphur content is used at power stations.

Every year the volume of coals with high sulphur content becomes smaller. The volume of mining and marketing of steam coals with low sulphur content (0,2-I%) is increasing on account of Eastern coal basins development.

Steam coals of Moscow region coal basin have the highest sulphur content.

In accordance with growing demands to the quality of commercial coals great attention is paid to the cleaning of Moscow region coals. Coals of Moscow region coal basin are characterized by high pyrite content.

Investigations of Moscow region coals showed that in the process of mining and crushing of coarse coal before coal preparation concretions of pyrite were opened and they were not bind with organic matter of coal. It gives the opportunity to reduce sulphur content of commercial coals and simultaneously to separate pyrite for chemical industry, to minimize atmosphere pollution with noxious sulphur compounds and to improve the utilization of natural recources.

The developed classification of Moscow region coals according to sulphur content of cleaned coal helped to solve a range of problems on complex utilization of coal.

It is necessary to emphasize that sulphur content in pyrite of Moscow region basin coals is high and it accounts to 42-43%.

Investigations proved the possibility of complex coal preparation methodes development. It will help to achieve the reduction of ash and sulphur content.

The investigations also showed that concomitant rock consisted of a variety of clay which could be used as raw material for construction industry.

Non-refuse technology is now used at coal preparation plant of the Kimovsky open-cast mine , the Moscow region coal basin. Clean coal blended with fines is delivered to power stations, sulphur pyrite is used for sulphuric acid production at chemical plants and clay is sent to construction material works (Fig.7).

All annual output of wastes (clay) of Kimovsky coal preparation plant is delivered to brick plant. The use of wastes helped to improve brick quality. Clay specification correspond to specifications of the brick yard.

They are:

alumina content -30,6%
iron oxide -9,7%
losses in the
process of roasting -29,5%
moisture -23%
size -0-300mm.

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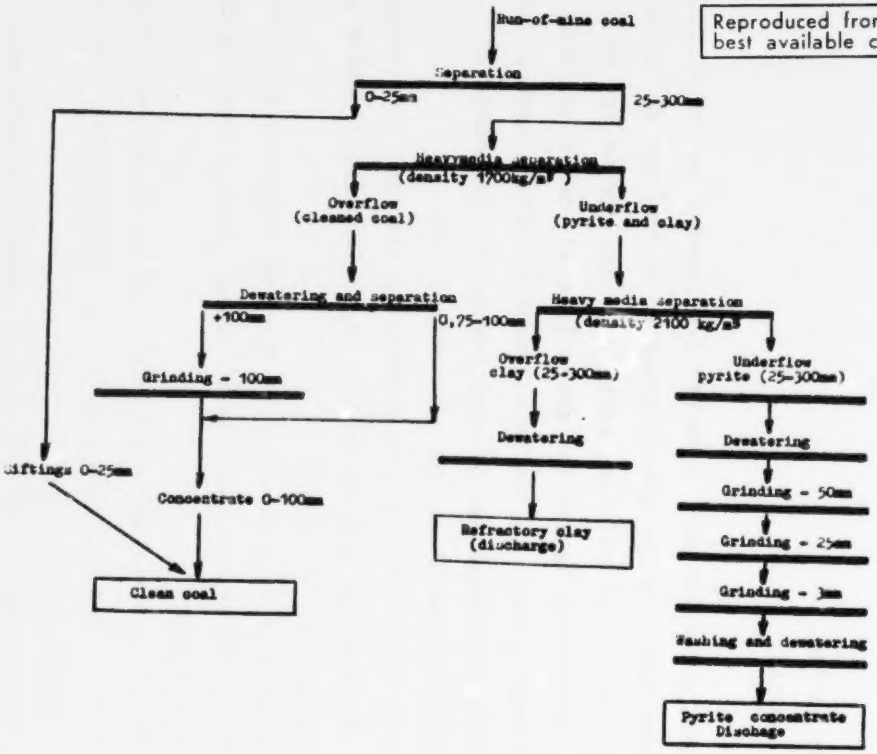
Run-of-mine coal
Separation
0-25mm
25-300mm
Heavymedia separation
(density 1700kg/m³)
Overflow
(cleaned coal)
Underflow
(pyrite and clay)
Dewatering and separation
+100mm
0,75-100mm
Grinding - 100mm
Siftings 0-25mm
Concentrate 0-100mm
Clean coal
Heavy media separation
(density 2100 kg/m³)
Overflow
clay (25-300mm)
Dewatering
Refractory clay
(discharge)
Underflow
pyrite (25-300mm)
Dewatering
Grinding - 50mm
Grinding - 25mm
Grinding - 3mm
Washing and dewatering
Pyrite concentrate
Dischage

Fig. 7 Flowsheet of Coal preparation plant "Kimovskaya"

For pyrite separation from Moscow region coals various types of flowsheets providing dry and wet methods of coal preparation are developed. Problems of development and introduction of efficient technology for pyrite separation in the process of dust preparation and burning of high sulfur coals at power stations are of great interest.

Reduction of coal losses in the process of mining and cleaning.

One of the main trends for coal industry development is the increase of open-cast mining output based on the use of advanced technology and modern techniques. As a result, the use of existing techniques and technology in complicated geological conditions causes the great loss of coal from thin seams. The reduction of coal losses by the improvement of mining methods has not been always justified. For reduction of coal losses in stockpills of open-cast mines it is advisible to clean the diluted raw coal.

For reduction of coal losses in the process of raw coal preparation and for improvement of cleaned coal quality simple technology and a number of counter-flow separators have been developed.

The,advantages of these separators are: the simplicity of construction, easy maintenance and repair and high technological coefficients providing the reduction of coal losses in wastes.

Such flowsheets are introduced at I0 coal preparation plants. Four types of high-slope separators KNS with the capacity to 400 tons per hour are used for separation of diluted steam coals.

Environment control regulations for coal preparation plants are developed and adopted by the Ministry of Coal Industry of the USSR for five years with the indication of annual work.

USSR Ministry of Coal Industry controls the fulfilment of environment protection regulations. Besides, control for environment protection and for utilization of natural resources at preparation plants of the USSR is carried out by medical, land reclamation and water management agencies, by State Committee of Hydrometeorology and Environment Control of the USSR, etc.

In conclusion, it is necessary to emphasize that research and development cooperation between plants and institutes of the USSR Ministry of coal industry and USA environment protection departments in the field of development and introduction of efficient environment protection methods can be useful for both countries.

THE CLEAN FUEL SUPPLY: FACTORS AFFECTING U.S. AND EUROPEAN SO_2 EMISSIONS IN THE MID-1980's

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ABSTRACT

This paper analyzes the factors affecting the availability of low-sulphur fuels and the introduction of fuel desulphurization technologies in the OECD region up to the mid-1980's. The analysis examines energy scenarios for North America, Western Europe, Japan, am Oceania, developed by the International Energy Agency in the context of the various SO_2 emissions reduction policies now being contemplated by the OECD member countries. The most probable forecast of 1985 SO_2 emission for OECD as a whole is 57 million metrictons, a 23 percent increase over the 1974 levels.

I. INTRODUCTION

This paper summarizes a report published in 1978(1) by the Environment Directorate of the OECD on the problem of limited supplies of clean fuel for the OECD Member countries. With increasing energy consumption, the supply of clean fuel may not be sufficient to meet future levels of demand created by more countries seeking to reduce emissions of sulphur oxides. The term "clean fuel" is used here to refer to fuels from which there are low emissions of sulphur oxides, principally sulphur dioxide (SO_2). These can either be naturally low in sulphur, or be desulphurized prior to combustion. If the factors which affects this supply of clean fuel can be identified, it may be possible for governments to take action where required, individually and collectively, to increase the supply of clean fuels and fuel cleaning techniques. It will also be possible to determine when it makes more sense to desulphurize the gaseous combustion products thus allowing high sulphur fuels to meet low emissions standards for SO_2.

All OECD countries have recognized the need to attain acceptable ground level concentrations of SO_2 and many have implemented ambient air quality standards and/or emission standards for it. The transport of SO_2 across frontiers has also concerned many countries. The overall solution to the problem will only be found through international cooperation in which national policies are implemented to attain acceptable ambient air quality, while at the same time minimizing transport across frontiers.

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(1) Clean Fuel Supply - Factors Affecting SO_2 Emissions in the Mid-1980's, OECD, Paris, 1978.

This paper analyses the situation in the three geographical regions of OECD, namely, Europe, North America and Japan. (Australia and New Zealand have been excluded. However preliminary calculations show that total SO_2 emissions from fuel combustion in these countries are relatively low, although these may be concentrated in certain areas).

The time frame for this report is 1985. This recognizes the fact that any decisions taken on clean fuel supply or fuel cleaning techniques would not have any major impact until the mid 1980's because of the long investment lead times involved. Only those technologies that have already been commeercially developed are considered as being available for wide scale application for 1985. Therefore, the report does not include such technologies as liquefaction, fluidized bad combustion and chemical cleaning of coal.

II. METHOD

The approach used by the OECD Environment and Energy Group is based on the study of the recent estimates for the years 1974 and 1985 of energy consumption and supply prepared by the International Energy Agency for the OECD for 1974 and 1985 (World Energy Outlook, IEA, 1976). Since the sources of supply and the distribution of sulphur in fuel sources over that time period are already fairly much determined, it is also possible to make projections of sulphur oxide emissions. These projections are presented in Table I.

(10^6 metric tons of SO_2)

	1968	1974	1985 Reference Case	1985 Accelerated Policy Case
OECD Europe	16.67	19.7	22.1-25.4	19.6-21.4
North America	26.6	24.2	24.9-28.1	22.4-25.7
Japan	4.0	2.4	2.6-3.1	1.7-3.3.
TOTAL	47.3	46.3	49.6-57.1	43.7-50.4

TABLE I SUMMARY OF ESTIMATED AND FORECAST SO_x EMISSIONS IN THE OECD, 1968 to 1985

The study shows that, for OECD as a whole, total SO_2 emissions from fuel combustion in 1974 were about the same as in 1968, despite a 26 percent increase in fuel consumption. The SO_2 emissions from fuel combustion were forecast for 1985 assumed no increase of desulphurization capacity over that already installed and planned. In the "worst" case there could be an increase of about 23 percent over the 1974 levels. In the "best" case, assuming that countries strive towards their energy independence objectives, (accelerated development of indigenous resources, increased conservation and increased use of low sulphur oil) there could be a decrease of the order of 6 percent or some 2.7 million metric tons of SO_2. The effect of energy policy can be seen to be critical.

If the OECD countries were to achieve the goals of energy conservation and development of indigenous energy resources set out in the Accelerated Policy Case, the sulphur emission standstill trend which has existed in OECD from 1968 to 1974 would probably continue up to 1985. However, the Accelerated Policy Case has been judged unrealistic for most OECD countries and the Reference Case, which assumes a continuation of present policies governing energy supply and conservation by OECD countries, is now considered to be the better forecast. There are also fears that even certain expectations in the Reference Case may not be realized. Perhaps the most important factor will be the share of total energy that nuclear power is forecast to provide. If nuclear output falls short of projections there will be a tendency to shift to fossil fuels and a consequent increase in SO_2 emissions. In this situation oil will be the balancing fuel and will of necessity be made up of the medium to high sulphur Saudi Arabian crude oils.

Given this general energy situation, the next step was to investigate the potential reductions in SO_2 emissions that could be achieved in the various OECD regions. Table II gives the distribution of SO_2 emission between coal and oil use in

Region & Fuel	% of Total SO_x Emissions 1985	Max. Potential for Further Reduction * (Percent of total SO_x emissions)
I. OECD Europe		
Oil	67	HDS = 33%, FGD,= 36%
Coal	33	FGD = 25%, Coal washing = 5%
	100	
II. Japan		
Oil	90	HDS = 18%, FGD 22%
Coal	10	FGD, Coal Washing = Neg.
	100	
III. USA		
Oil	20	HDS, FGD = Neg.
Coal	80	Coal washing = 20%, FGD = 20%
	100	
IV. Canada		
Oil	74	HDS = ? FGD = 6%
Coal	26	Coal washing = ?, FGD = 10%
	100	

* Over currently projected control measures for SO_x in 1985

TABLE 2. DISTRIBUTION OF SO_x EMISSIONS

1985 in OECD and the possible improvements that could be achieved by the available sulphur reduction technologies. For Japan, where oil is the dominant source of emissions, coal cleaning can have no real effect. Therefore, the emphasis must be on oil desulphurization prior to combustion, or flue gas desulphurization afterwards.

For OECD, Europe, despite the fact that coal contributes one-third of the SO_2 emissions, the potential reduction by coal washing is only about 1%. This is due to particular factors in the U.K. and Germany, the two principle coal consumers in this region. In the U.K. approximately 80% of the coal combusted now receives some degree of washing primarily to reduce ash content and upgrade heating value. In Germany, also, about 85% of the hard coal produced is washed. Furthermore, increases in German output are expected to be in the form of lignite, in which the sulphur content is essentially 100% organic, and thus not susceptible to removal by physical coal cleaning methods. Consequently, for Europe, the emphasis for SO_2 reduction will have to be FGD and oil desulphurization, although some improvement is also possible through increased coal washing, and careful matching of washed coal products with combustion clean up technology.

In OECD North America, both Canada and the U.S. show considerable potential for reduction in emissions from coal. In U.S. the maximum estimated reduction would be 20% from coal washing. This is due to the overall high pyritic sulphur content of U.S. coal, the relatively high proportion of energy produced from coal; and the relatively low proportion (under 25%) assumed to be washed. Canada shows the same pattern, although Canadian total SO_2 emissions amount to less than 10% of the U.S. The next stop of the study was to examine in detail the different sulphur reduction options in each region; and the associated costs, in order to arrive at an estimate of the most feasible strategy for emissions reduction.

III. COAL CLEANING FOR OECD EUROPE

As the physical properties of coal and coal cleaning practices and costs vary considerably from one coal producing country to another within the OECD European region, and economic analysis of coal cleaning in the region as a whole would not be sufficiently representative for the coals of any one country. In addition, coal properties and, therefore, cleaning potential are best documented for the two major producers the Federal Republic of Germany and the United Kingdom. By 1985 Germany plans to clean all coal to produce a clean product having an average sulphur content of about 1.0 percent down from about 1.39 in its natural state. The present coal cleaning practice in the United Kingdom is not oriented specifically towards sulphur reduction but reaches towards producing a coal of uniform heating value and low ash content. Taking the United Kingdom as an example for Europe, costs have been analysed for desulphurization by coal cleaning.

In considering the current U.K. coal cleaning practice there is potential for reorienting this practice to increase sulphur removal. Three levels of cleaning can be examined:

(a) cleaning to produce a single product coal of uniform heating value and ash content,

(b) cleaning at two specific gravity separations to redistribute sulphur into a clean low-pyritic sulphur coal product and a middlings product with higher sulphur, and

(c) redistribution as in (b), cleaning of the middlings to reduce sulphur and blending with clean coal product.

The redistribution of sulphur into the two product streams does not in itself reduce the overall sulphur content of the coal. It is through further processing of the middlings, for example by regrinding, more washing and froth flotation, that the SO_2 emissions reduction can be achieved. Alternatively, the middlings may be used where FGD is applied to the post-combustion gases. The costs of these two alternatives may be compared.

The costs for a new coal cleaning plant for each of these levels of cleaning have been estimated by a group of experts, as shown in Table III. The operating costs in this table include only operation and maintenance. To complete the analysis, it is necessary to add the annualized capital charges which are estimated at 20 percent of the capital investment per annual ton of capacity. For 3,000 hours per year of operation, this amounts to $1.70 per metric ton. The 1976 total cleaning cost would be $2.80 per metric ton raw coal ($4.70 per metric ton washed coal).

In 1974, the U.K. coal consumption was 94 x 10^6 metric tons of which about 60 x 10^6 metric tons were cleaned. In 1985 the coal consumption is forecast to be slightly higher. The annual operating cost in 1985 to produce coal of uniform heating value and ash content is $6.10 per metric ton of washed coal (escalated to a 1980 dollars basis). To redistribute the sulphur in the coal (level b) or reduce sulphur further (level c) would increment the annual operating cost of $6.10 per metric ton by the costs shown in Table IV. The total cost of $7.50 - 8.25 per metric ton would represent the sulphur premium for desulphurized coal (level c) over washed coal and the cost of $1.40 - 2.15 would represent the premium over washed coal (level a).

It has been estimated that washing U.K. coal at specific gravities of 1.3 and 1.8 would produce about one-third middlings at 2.5 percent to 3.0 percent sulphur and about two-thirds clean product at 1.0 percent sulphur. As the organic sulphur content of the coal (0.8 to 1.0 percent) would be almost the same for the clean product and the middlings, the pyritic sulphur content of the middlings would be in the range of 1.5 percent to 2.0 percent sulphur. It is expected that further processing could reduce the middlings sulphur content from 2.0 to 1.8 percent with a minimum loss of coal to the waste. The

(Currency at December 1976 values)*

	Capital Costs (currency/metric ton of raw coal/hr)		Operating Costs (currency/metric ton of raw coal)	
	FRG	UK	FRG	UK
Base cost to produce coal of uniform heating value and ash content	30-40,000 DM ($12-16,000)	£15,000 ($25,000)	2.5-3 DM ($1.00-1.20)	70 p ($1.17)
Incremental cost over base (redistribute pyritic sulphur into product and middlings)	+ 12% (assumes dense medium cyclones at SG = 1.30-1.32)		5-16%	
Incremental cost over base (redistribution and reduction of sulphur by secondary processing of middlings)	25-32%		20-40	

* $1.00 = 2.50 DM, 0.60£

TABLE 3: COSTS FOR NEW COAL CLEANING PLANTS

ultimate coal sulphur content, if clean coal and middlings were blended after all processing, would be about 0.25 percent sulphur lower.

From Table 4 the incremental cost of sulphur removal (level c) over washed coal (level a) is in the range $560 - 860 per metric ton of sulphur. However, if existing cleaning practice is such that only some small percentage of coal is cleaned, then to the above incremental cost it would be necessary to add a share of the cost for coal washing, that is the cost of increasing the percentage of coal cleaned. For example, at present about 50 percent of U.K. coals for electricity sector combustion are washed. To increase the sulphur removal on these 50 percent would cost $560 - 860 per metric ton sulphur removed. If the other 50 percent of the coal were to be treated for sulphur removal a 50 percent share of the base cost would be included, making the average cost for all 100 percent of coal equal to $1,800 - 2,100 per metric ton of sulphur removed.

In conclusion, for the countries which wash a large percentage of combustion coal production, a cleaner low sulphur product can be obtained at an incremental cost of $1.40 - 2.15 per metric ton of coal or at a sulphur removal cost of $560 - 860 per metric ton of sulphur. Sulphur removal costs increase if a lower percentage is generally washed. For Europe in 1985, if all combustion coal could be reduced by 0.25 percent sulphur content on average by this method, the quantity of sulphur removed would be 0.5 - 0.6 x 10^6 metric tons. The potential removal is limited, but coal cleaning may be the most economic method for coal desulphurization.

IV. FLUE GAS DESULPHURIZATION

The basis used for flue gas desulphurization costs for coal-fired power plants assumes particulate control to 0.1 lb/

	Incremental Operating Cost ($/metric ton washed coal)*	Increment of Sulphur Removed (% wt. S)	Incremental Cost of Sulphur Removal ($/metric ton of sulphur)*
Redistribute sulphur into product and middlings	0.55-0.85	0	-
Redistribution and secondary processing of middlings	1.40-2.15	0.25	560-860

* $ are 1980 US $

TABLE 4: SULPHUR REMOVAL AND INCREMENTAL OPERATING COSTS OVER BASE COST FOR REDISTRIBUTING PYRITIC SULPHUR AND REPROCESSING MIDDLINGS, UK

million Btu.** The basis and the cost equations are presented in Table 5. The costs shown assume sulphur contents for each solid fuel as follows:

. hard coal:	the European average of 1.35% S in the 1985 Reference Case,
. middlings:	2.75% S, within the range expected for washing U.K. coals at specific gravities of 1.3 and 1.8 to produce clean product and middlings,
. lignite:	the European average of 1.15% S in the 1985 Reference Case.

In determining the sulphur reduction, the sulphur normally retained in the ash has not been included as part of the reduction.

As expected, the costs are much higher for FGD on hard coal-fired power plants because of the relatively low sulphur content of European hard coals. The FGD costs for new plants ranging from $1,039 - 1,783 per metric ton of sulphur removed are much higher than coal cleaning costs, $560 - 860 per metric ton of sulphur removed. However, in the case of U.K. coals for electricity sector combustion where only 50 percent are washed, the cost of coal cleaning, $1,800 - 2,100 per metric ton of sulphur removed is higher. It is also clear that retrofit of FGD on existing coal-fired plants would rarely be economical.

For lignite combustion, the costs of FGD are much more attractive. Since lignites are often very low in pyritic sulphur content and cannot be desulphurized by washing, FGD is the only option for sulphur removal. Since over 80 percent of European lignites will be consumed in power plants

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*** metric equivalent is 0.18 kg/kcal

AVERAGE ANNUAL OPERATING COST (Size in MW; H in hours/yr operation)

Basis: Limestone Scrubbing, 1980 Cost Basis ($/metric ton S removed)
90% S removal, with sludge fixation and
disposal, with flue gas reheat, and,
particulate control to 0.1 lb/million Btu of heat
input.

I. FGD on New Coal-Fired Power Plant (particulate control)

$$\text{Cost} = \left[\frac{\text{Size}}{(500)}\right]^{0.7} [6708 + 676(\%S)^{0.7}] + \left[\frac{\text{Size}}{(500)}\right] [0.664 + 0.1019\ (\%S)](H)$$

$$\text{Sulphur removed (metric tons/yr)} = 1.457(\%S)\left[\frac{\text{Size}}{(H)(500)}\right]$$

II. FGD on Existing Coal-Fired Power Plant (particulate control)

$$\text{Cost} = \left[\frac{\text{Size}}{(500}\right]^{0.7} (R)\ [6708 + 676(\%S)^{0.7}]$$

$$+ \left[\frac{\text{Size}}{(500)}\right] [0.859 + 0.1984(\%S)]\ (H)$$

a) R is 1.2 for easy retrofit and 1.4 for difficult retrofit

b) Sulphur removed (metric tons/yr) = $1.490(\%S)(H)\left(\frac{\text{Size}}{500}\right)$

TABLE 5: SUMMARY OF FGD COST EQUATIONS

in 1985, the potential exists to remove 1.2 x 10^6 metric tons SO_2 from new lignite-fired power plants and 0.7 x 10^6 metric tons SO_2 from retrofit of the newer and larger existing lignite power plants.

V. COAL CLEANING vs FLUE GAS DESULPHURIZATION FOR OECD EUROPE

For hard coal, it may be more economical to use a combination of coal cleaning and FGD where the coal cleaning is used to segregate a middlings product for use in power plants with FGD.

From Table 4 the incremental cost of segregation of washed coal into clean coal and middlings is $0.55 - 0.65 per metric ton of coal washed. Similarly the incremental cost of segregation of an unwashed coal is $6.65 - 6.95 per metric ton of coal washed. The net segregation cost in 1985 would be proportioned to the mix of washed and unwashed coal in a given country.

After segregation, two options exist for the middlings. The first is to further the process middlings at the cost of $0.85 - 1.30 per metric ton of washed coal. The second is to use the middlings in a power plant with FGD at operating costs ranging from $598 - 988 per metric ton of sulphur removed for new power plants, or $14 - 24 per metric ton of coal combusted.

Table 6 summarizes the total cost for these two options for two cases of different washing practices. For the option of segregation with further processing of middlings, the cost per ton of coal in the table are simply the total cost of segregation and further process of middlings distributed over only the cleaned coal product (approximately two-thirds of the products).

	Option 1 Coal Segregation and Processing of Middlings (no FGD)		Option 2 Coal Segregation with Middlings to FGD	
Normal Practice for Combustion Coal	($/metric t. clean coal product)*	($/metric (tons S)*	$/metric ton coal)*	($/metric (ton S)*
100% washed coal	1.25–1.95	560–860	6.00–10.20	770–1300
50% washed, 50% unwashed coal	5.80–6.55	1800–2100	9.10–13.20	1160–1680

* 1985 operating costs in 1980 US $

TABLE 6: INCREMENTAL COST FOR SULPHUR REMOVED BY COMBINED COAL WASHING AND FGD

For the other option of segregating middlings for use with FGD, it is necessary to have a price differential between the cleaned coal and the middlings which would be sufficient to offset the cost of FGD. In this case, the cleaned coal product must also bear the cost of segregation. The cost per ton of coal in the table represents the price margin above the base cost for washed coal necessary to establish the price differential. For the example in Table 6 this price differential would be set at \$14 - 24 per ton of coal.

It can be seen from Table 6 that, if the existing practice is to wash a high proportion of power plant coal, then cost of optional sulphur removal at the coal cleaning plant in terms of incremental cost per ton of sulphur removed for improved sulphur removal in the coal cleaning plant is much less than the cost of producing high sulphur middlings for use with FGD (option 2). If the existing practice is to wash a lower proportion of power plant coal then the reverse may be the case. However, it should be remembered that, in all cases, FGD has the potential to remove much larger amounts of sulphur than does the coal cleaning.

If, in Europe in 1985, all power plants greater than 100MW capacity constructed since 1975 were to use segregated middlings as in option 2, then the sulphur removal would be 1.4×10^6 metric tons from the combustion of about 60×10^6 metric tons middlings. The total annual operating cost for such a strategy is in the range \$1,100 - 2,400 $\times 10^6$. In comparison, for sulphur removal from segregation and further processing of middlings for all combustion coals would be only $0.5 - 0.6 \times 10^6$ metric tons.

Another cost analysis of coal cleaning with scrubbing for sulphur control was carried out by the U.S. EPA*. The report examined a number of case studies combining some physical coal cleaning of some of the combustion gases to meet the U.S. Federal standard of 1.2 lbs/MBTU for SO_2 emissions. It was concluded that, in many cases, the net cost of physical coal cleaning followed by scrubbing of part of the flue gas to meet standards is substantially less than that associated with using only a full scale scrubbing system. However, this conclusion depends upon cost benefits from using clean coal, such as increased heat content, transportation savings, ash disposal savings and pulverising savings. Whether this approach would have the same cost benefit in Europe would therefore be dependent on whether the benefits of using cleaned coal are already being realized. In countries where a significant proportion of coal is not already cleaned the combined approach may have a cost benefit.

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*Coal Cleaning with Scrubbing for Sulphur Control: An Engineering/Economic Summary, EPA-600/9-77-017, USEPA, August 1977.

In conclusion, it is apparent that for most European hard coals, coal cleaning to reduce sulphur content will be the most economical approach either because of lowest incremental cost or because of other benefits derived from the use of clean coal. However, if further sulphur reduction is needed beyond that which is possible with coal cleaning, a high sulphur middlings should be segregated for use in a power plant with FGD.

North America

Performing a similar analysis for North America, begins with projections of FGD in 1985. For the eleven year period from 1974 to 1985, the North American fossil fuel fired electric generation capacity is expected to grow as shown in Table 7. During this period, it is estimated that there will be 48 GW of expansion capacity and about 20 GW of new capacity to replace retired capacity.

A group of experts on flue gas desulphurization was asked by the OECD to forecast the amount of FGD capacity in

	Fossil Fuel Capacity GW	Average Load Factor	Sulphur Containing Fuels			Total Fossil TWh
			Coal TWh	Lignite TWh	Oil TWh	
1974	375	0.51	993	19	326	1721
1980	404	0.51	1081	29	348	1805
1985 Ref.	425	0.56	1415	42	334	2086
1985 AP	423	0.54	1362	41	216	2017

TABLE 7 THE NORTH AMERICAN POWER PLANT FORECAST FOR 1985

North America in 1985. Their estimate was as follows:

	1976 (GW)	1985 (GW)
United States	6.5	46.4-80.0
Canada	-	3.0- 5.0
OECD	6.5	49.4-85.0

The United States estimate depends on the number of utilities that must retrofit with flue gas desulphurization and the ability to meet the NSPS with other technologies by 1985.

In the United States, it is expected that the flue gas desulphurization capacity will be on coal-fired units only burning coal with a 2.0 percent sulphur average, with a boiler load factor of 0.65 average and an FGD removal efficiency of 90 percent and reliability of 100 percent. Then the emissions reduction can be calculated to be 4.3 - 7.4 million metric tons SO_2. It is alos expected that the design, operation and maintenance of FGD units by 1985 will have reached a state of expertise such that 100 percent reliability during the period of boiler operation will be realizable. An average sulphur content of 2 percent for coal was used on the basis that the U.S. average coal sulphur content will be about 1.6 percent S in 1985 but that the low sulphur fraction will be used for plants without FGD, leaving a higher sulphur fraction for use with FGD.

In Canada, it is expected that half of the flue gas desulphurization capacity will be solely coal-fired units only in the eastern provinces from Ontario eastward, burning high sulphur coals of 3.0 percent S, with a boiler load factor of 0.55 and an FGD removal efficiency of 90 percent and reliability of 100 percent. Then the emissions reduction from coal can be calculated to be 0.18 - 0.29 million metric tons SO_2. The other half would be on oil-fired boilers with 2.8 percent S oil. This would produce emissions reduction from oil of 0.09 - 0.15 million metric tons of SO_2.

If the forecasts of FGD capacity in 1985 are met, the North American electric power producers will have installed the maximum technologically feasible flue gas desulphurization capacity.

U.S. Coal Cleaning Potential

The present coal preparation practices separate the raw coal into a clean coal and a waste. In operating the units, there is a trade-off between the sulphur removal and the loss of coal into the waste. For the purpose of analysis those levels of coal preparation are defined:

Level A - Coal is crushed to 1-1/2 inch top size and beneficiated with 90 percent BTU recovery;

Level B - Coal is crushed to 1-1/2 inch top size and beneficiated with 80 percent BTU recovery;

Level C - Coal is crushed to 3/8-inch top size and beneficiated with 80 percent BTU recovery.

It should be noted that the resulting estimated sulphur contents of cleaned coal Table 8 are those obtained by float-sink analysis at the given Btu recoveries, and they may differ from the actual values obtained in commercial coal cleaning plants. There are two major factors which affect the sulphur removal by coal cleaning:

(a) Inefficiency of coal cleaning equipment: The sulphur content of commercially cleaned coal is generally higher than that obtained float-sink analysis if the Btu recoveries are the same.

(b) Btu recovery: In general, for any given coal, the lower the Btu recovery, the lower the sulphur content of the cleaned coal. The average Btu recovery in commercial coal cleaning plants is approximately 80 percent.

A forecast of the quantity of U.S. coal to be cleaned and estimates of the quantity of sulphur which could be removed in 1985 are summarized in Table 8 which shows that the total coal to be produced in that year to be 1040 x 10^6

Region	Total Coal Prodn. (10^6 short t.)	Estimated Mech. Cleaning (10^6 short t. Cleaned Coal)	Total Sulphur Content (wt.per cent)				Estd. Sulphur Removal (10^6 short t.)		
			Raw Coal	Level A Cleaned	Level B Cleaned	Level C Cleaned	Level A Cleaned	Level B Cleaned	Level C Cleaned
Northern Appl.	183	88.3	3.01	2.06	1.83	1.61	1.13	1.71	1.90
Southern Appl.	322	133.2	1.08	0.97	0.96	0.94	0.31	0.52	0.55
Eastern Midwest	156	97.6	3.92	2.73	2.57	2.47	1.59	2.27	2.37
Western Midwest	9	0.9	5.25	3.91	3.76	3.45	0.02	0.03	0.03
Western	370	53.2	0.68	0.54	0.51	0.53	0.11	0.18	0.17
Total	1040	373.2	2.20	1.63	1.53	1.45	3.16	4.71	5.02

TABLE 8: ESTIMATED MECHANICAL CLEANING OF BITUMINOUS COAL AND LIGNITE IN 1985

short tons of which an estimated 373.2 x 10^6 short tons will be mechanically cleaned. The quantity of sulphur removed is estimated to be in the range 3.2 x 10^6 short tons.

The coal to be used for coking and export in 1985 is estimated to be 182.8 x 10^6 short tons for the Reference Case (averaging 1.0 percent sulphur). Hence, mechanically clean coal used for combustion is estimated to be 190.4 x 10^6 short tons with the average sulphur content for all combustion coals in the range 1.57 to 1.64 percent.

For the Accelerated Policy Case, the average sulphur content of coals for combustion domestically would be in the range 1.57 to 1.59 percent.

Although the above estimates of the quantity of coal to be cleaned in 1985 for combustion purposes are likely to be conservative, the most conservative Level A cleaning was assumed in forecasting the 1985 emissions for the U.S.

In order to determine the maximum possible sulphur removal, it is useful to examine how much mechanical cleaning of coal is feasible. The quantity of sulphur removed would be augmented considerably if 100 percent of the high sulphur Northern Appalachian, Eastern Midwest and Western Midwest coals were to be cleaned. Since little benefit would result by increased cleaning of the low sulphur Southern Appalachian and Western coals, the present percent of cleaning is not changed. At Level A cleaning, the estimated sulphur removal would be increased to 5.56 x 10^6 short tons from the 3.16 x 10^6 short tons shown in Table 8. For Levels B and C, the estimated removal would be 8.12 x 10^6 and 8.73 x 10^6 short tons sulphur respectively. Hence the total increased from 190.4 x 10^6 short tons in the Reference Case to 351.6 x 10^6 short tons, and the average sulphur content for all combustion coals would be in the range 1.30 to 1.45 percent. Similarly for the Accelerated Policy Case, the average for all combustion coals would range from 1.30 to 1.44 percent sulphur.

An alternative strategy would be to clean the coal at two specific gravity separations to redistribute sulphur into a clean low sulphur coal product and a middlings product with higher sulphur. The advantage in doing this is that, by either further cleaning the middlings or applying post-combustion emission control to their combustion, the SO_2 emissions reduction is maximized without the need to progress to the cleaning of the total coal production to lower overall sulphur levels.

Table 9 summarizes the estimated sulphur content of coals in 1985 if all coals were processed through a 1.3 specific gravity separation to produce a clean product, followed by a 1.6 specific gravity separation to produce a middlings product. It shows that the clean product (1.3 s.g. float) from each region would contain much lower sulphur content than the middlings (1.3 s.g. sink and 1.6 s.g. float).

In Table 10, the strategies are combined in the best manner to produce two coal products one for combustion without flue gas desulphurization (FGD) and the other requiring FGD. This would result in 667.7×10^6 short tons of combustion coals in the 1985 Reference Case having a 1.07 sulphur content and the remaining 189.5×10^6 short tons having 80 percent of the sulphur removed by FGD giving them an effective average sulphur content of 0.60 percent.

However, the constraints on achieving these levels of cleaning by 1985 are many. Not only is a greatly increased cleaning plant capacity required but also the quantity of raw coal mined would need to be greater to compensate for the heating value loss during cleaning.

Region	Total Coal Production (10^6 short tons)	Clean Product (1.3 SG Float) (10^6 short tons)	Middlings (1.3 SG Sink 1.6 SG Float) (10^6 short tons)	Total Sulphur Content (wt. %)		
				Raw Coal	Product	Middlings
Northern Appalachian	183	69.8	113.2	3.01	1.41	2.56
Southern Appalachian	322	185.1	136.9	1.08	0.86	1.10
Eastern Midwest	156	84.5	71.5	3.92	2.35	3.53
Western Midwest	9	4.2	4.8	5.25	2.93	4.74
Western	370	217.1	152.9	0.68	0.55	0.60
Total	1040	560.7	479.3	2.20	1.05	1.68

TABLE 9: POTENTIAL SULPHUR REDUCTION OF US COALS IN 1985 AT 1.3 AND 1.6 SPECIFIC GRAVITY SEPARATION

VI. CONCLUSION

A. OECD North America

The study shows that the potential SO_2 emissions in North America in 1985 will come primarily from coal combustion in power stations. However, since the installed and planned flue gas desulphurization capacity in North America is large (50-80 GW), much of these potential emissions from power stations will be controlled. North America must achieve its planned FGD capacity to avoid an increase of emissions of 20-40 percent above the forecast.

As a result of this control technology and the fact that coal is domestically produced, the 1985 emissions in North America will be much less sensitive to the energy and fuel import policies than will be the emissions in Europe. The range shown in the summary Table 1 reflects only the uncertainty in the amount of flue gas desulphurization to be installed.

North America is the one OECD region where coal cleaning represents a method for substantial SO_2 emission reduction by 1985. This is due in part to the expected increase in coal use by 1985 and also to the fact that currently only a relatively small proportion of production for combustion is washed.

The segregation of coal in the washing plant into high and low sulphur fractions is feasible. This would permit higher sulphur coals and middlings from the washing plant to be used in the large number of power plants with flue gas desulphurization. The low sulphur coal million metric tons of coal averaging 1.0 percent sulphur content could be segregated out of the total 857 million metric tons of combustion coal.

B. OECD Europe

In order to achieve the maximum reduction of total SO_2 emissions, following European strategy would have the lowest cost of sulphur removal (1980 dollars):

- segregate high sulphur and medium sulphur residual fuel oils,
- install flue gas desulphurization in all oil-fired power plants over 200 MW,
- desulphurize by direct residue desulphurization the remaining high and medium sulphur residual fuel oils to a level of 0.5% S ($630-810/metric ton of S removed),
- physically wash all hard coals to minimize sulphur content ($560-2,100/metric ton of S removed),
- install FGD on all lignite-fired boilers over 100 MW and constructed since 1967 ($520-890/metric ton of S removed),
- require that all imported coals be washed to minimize sulphur content,
- use naturally low sulphur or cleaned fuel in the domestic, commercial and small industrial sector where FGD is not practical.

This strategy would remove approximately 13×10^6 tons of SO_2 from residual fuel oil combustion in 1985 at a total operating cost in 1985 of approximately $4 billion. It would also remove approximately 1×10^6 tons of SO_2 from hard coal combustion at an operating cost of approximately $0.35 billion and approximately 2×10^6 tons SO_2 from lignite combustion at $0.6 billion. In the 1985 "worst" case, SO_2 emissions would be reduced from 25.4×10^6 metric tons of SO_2 to approximately $9\text{-}10 \times 10^6$ metric tons at an annual operating cost of $5 billion.

If it is desired to maintain emissions at their present level of 20 million metric tons of SO_2 rather than to obtain the maximum emission reduction, a standstill strategy could be put into practice by 1985. In the "worst" 1985 case this would mean a reduction of 6 x 10^6 metric tons SO_2. The washing of all hard coals could reduce SO_2 emissions by 1 x 10^6 metric tons at an annual 1985 operating cost of approximately $0.35 billion. Installation of FGD on all new (post 1974) lignite-fired boilers over 100 MW would reduce SO_2 emissions by another 1 x 10^6 metric tons at $0.3 billion in 1985. The remaining 4 x 10^6 metric tons reduction could be accomplished by segregation of 4.0% S fuel oil to new power plants (post 1980) with FGD or by direct desulphurization of high sulphur residual oil to 0.5% S. (The cost of low sulphur fuel oil would be incremented by $7/metric ton). The 1985 operating cost would range from $1.0-1.25 billion for these two options. The SO_2 emissions could be reduced by only 3 x 10^6 metric tons by the purchase of additional cost of about $1.75 billion.

A standstill strategy which would require the removal of about 6 x 10^6 metric tons of SO_2 in 1985 would result in a 1985 annual operating cost of $1.55-1.80 billion.

A TECHNICAL AND ECONOMIC OVERVIEW OF COAL CLEANING

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ABSTRACT

This paper is based on work performed by Bechtel National, Inc., San Francisco, California, for Argonne National Laboratory, under an ongoing program on Environmental Control Implications of Generating Electric Power from Coal, sponsored by the Assistant Secretary for Environment, DOE, Division of Environmental Control Technology. From the broad subject of coal cleaning, the paper is limited to a technical and economical overview of physical coal preparation and cleaning technologies (CPC).

CPC processes can be divided into comminution, classification, separation, dewatering, and drying. A run-of-mine coal passes through all or any combination of these processes on its way to the consumer. Each process is performed in unit operations which may utilize various types of equipment and process principles. The unit operations are combined in CPC plants, in sequences depending on the raw coal characteristics and the extent of coal preparation and cleaning effort required to produce a marketable product or products. The objective is to strike an economic balance between high Btu recovery and reduced ash or sulfur levels. Five levels of CPC efforts have been defined, each of which (when used with the appropriate raw coal) can produce marketable products, i.e., at least one product which would release not more than 1.2 pounds of sulfur per million Btu when combusted.

The add-on costs to run-of-mine coal have been calculated based on the processing of five different coals, one for each level of effort. These costs include: capital cost, operating costs, and the cost of refuse disposal, as well as the cost of environmental controls. An equation has been developed which allows calculation of the total cost of upgraded coal at the CPC plant boundaries, including the raw coal cost.

INTRODUCTION

This paper discusses coal preparation and cleaning (CPC) and is limited to a technical and economic overview. The paper resulted from work on an ongoing Argonne National Laboratory (ANL) program, "Environmental Control Implications of Generating Electric Power from Coal." The program is directed at evaluating those environmental control technologies applicable to coal utilization systems. As part of the ANL effort, Bechtel National, Inc., performed a "Coal Preparation and Cleaning Assessment Study" for which a final report* has been prepared detailing the applicability, techniques, and economics of coal cleaning. The program is sponsored by the Assistant Secretary for Environment, DOE, Division of Environmental Control Technology.

Coal is found in seams embedded between sedimentary geological formations and is contaminated with varying degree by mineral matter. This contamination usually increases during mining due to the recovery of top and bottom material. After mining, the ROM coal consists of bulky material that is difficult to handle and to transport. CPC reduces the top size and upgrades the quality of ROM coal to produce a product that

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*Bechtel National, Inc., *Environmental Control Implications of Generating Electric Power from Coal, 1977 Technology Status Report,* Argonne National Laboratory Report ANL/ECT-3, Appendix A, Parts 1 and 2 (Dec. 1977).

is cleaner and more convenient to handle. The top-size reduction requires relatively simple technology. The top size of all the 600 x 10^6 TPY of ROM coal produced in the United States is reduced. About one-third of this production undergoes additional cleaning including 120 x 10^6 TYP steam coal. The primary objective of steam coal cleaning has been to remove ash in the form of mine dilutions to save transportation costs. Recently, however, another coal cleaning objective is to remove sulfur to help utilities meet sulfur-oxide emission regulations.

Sulfur appears in coal mainly in two forms – pyritic sulfur often of fine particle size and organic sulfur, which is part of the coal matrix. Processes are under development with the objective to remove all sulfur. However, this paper will address only commercially available, physical CPC technologies that are limited to separate pyrite from coal or at least that portion of pyrite that is liberated or can be economically liberated by crushing.

PHYSICAL CPC TECHNOLOGIES

Coal preparation and cleaning involves a number of unit operations that can be generally classified by the following categories: comminution, classification, separation, and dewatering and drying. The particular combination of unit operations depends on the raw coal characteristics and the quality criteria of the marketable products (particle size, Btu content, ash content, sulfur content, etc.). Some coals such as Eastern bituminous coals may be subjected to all of these unit operations before they are marketed, while low sulfur Western subbituminous coals only require crushing.

Figure 1 is a simplified schematic of the major unit operations in CPC plants. Rotary breakers or roll crushers are used for comminution of the ROM coal and screens for size classification before the coal enters equipment to separate the impurities. After the separation, screens, centrifuges, and filters are used to recover the coal and refuse from the separating medium, which sometimes includes thermal drying for the coal product. The removal of mine dilutions from steam coal has required mainly low cost coal cleaning with minimal comminution. However, as the demand for the removal of pyrite increases, the trend is toward more crushing and increased processing of fine material.

Comminution

The crushing of coal can have two objectives:

- Top size reduction
- Liberation of mineral matter such as pyrite

Various types of crushers have been developed to pursue these objectives. Figure 2 shows applications of the various types of crushing equipment in use today with rotary breakers and roll crushers for top size reduction with minimum fines

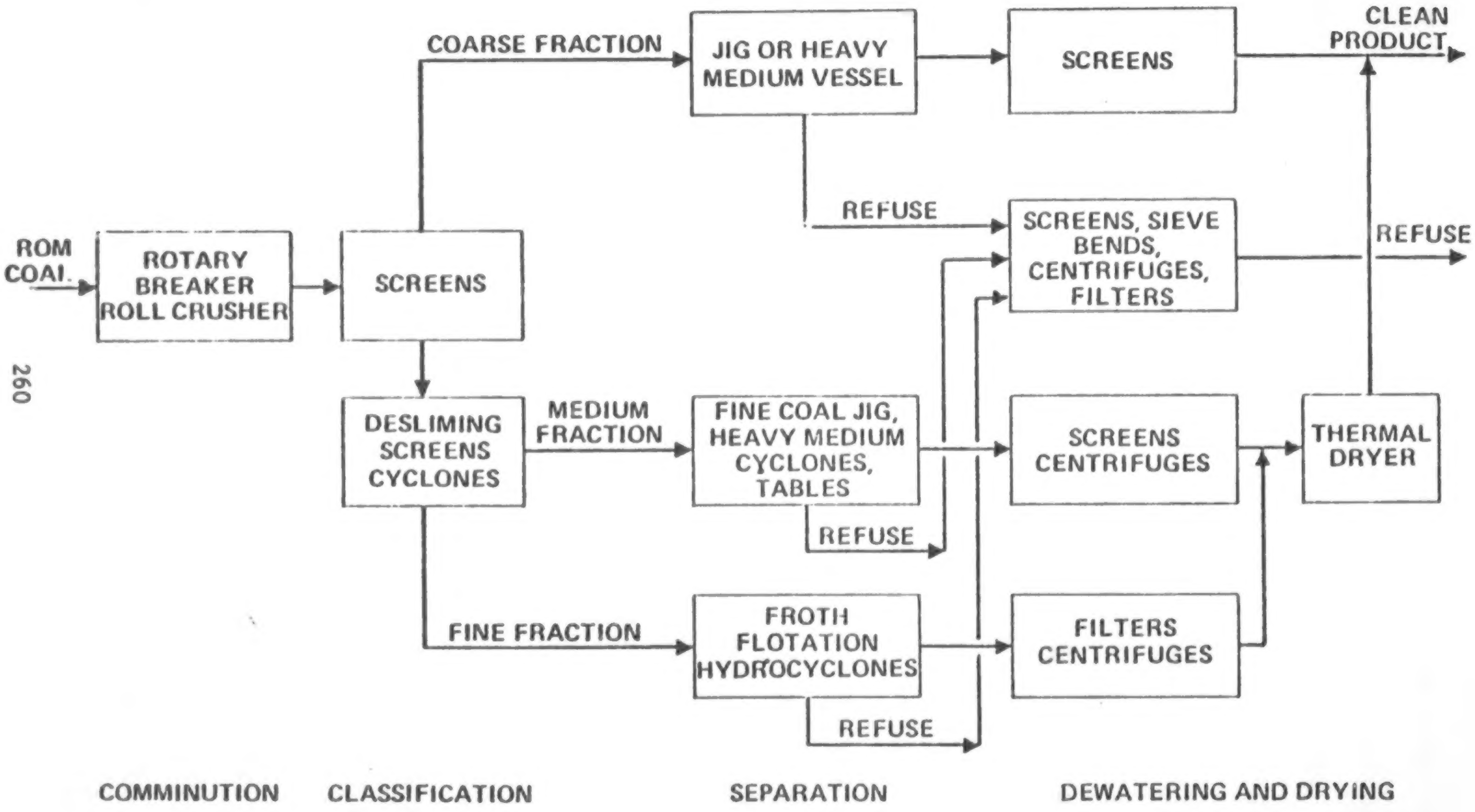
ROM COAL
ROTARY BREAKER ROLL CRUSHER
SCREENS
COARSE FRACTION
DESLIMING SCREENS CYCLONES
MEDIUM FRACTION
FINE FRACTION
JIG OR HEAVY MEDIUM VESSEL
REFUSE
FINE COAL JIG, HEAVY MEDIUM CYCLONES, TABLES
REFUSE
FROTH FLOTATION HYDROCYCLONES
REFUSE
SCREENS
SCREENS, SIEVE BENDS, CENTRIFUGES, FILTERS
SCREENS CENTRIFUGES
FILTERS CENTRIFUGES
THERMAL DRYER
CLEAN PRODUCT
REFUSE
COMMINUTION
CLASSIFICATION
SEPARATION
DEWATERING AND DRYING

Figure 1. A simplified schematic of the major unit operations in a CPC plant.

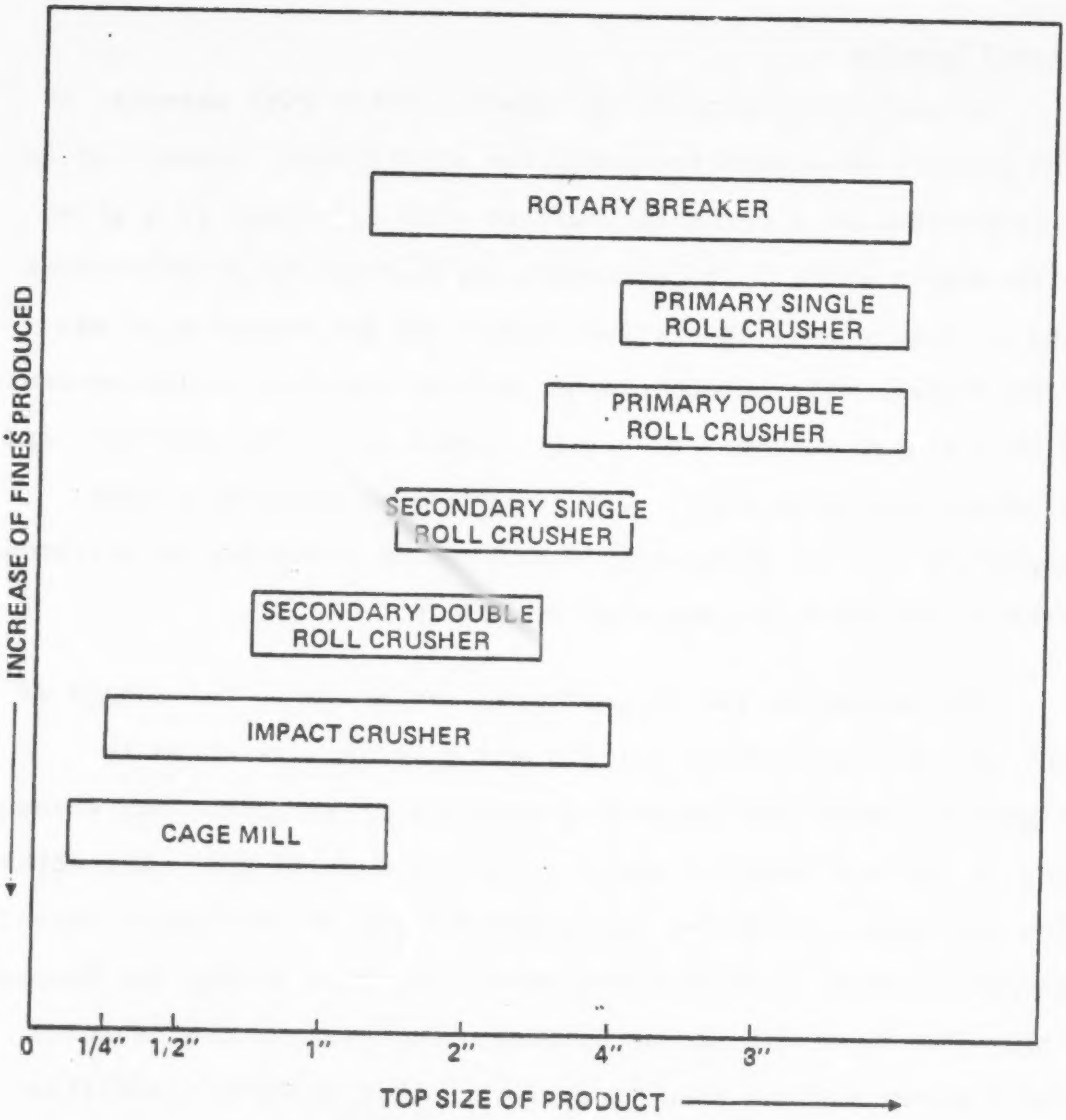

Figure 2. Range of application for crushing equipment in coal preparation and cleaning.

production and impact crushers and cage mills for mineral matter liberation. Figure 3 shows the relation of the particle size distribution when different kinds of crushers are used for medium hard coal.

Classification

Classification, performed predominantly with screens, is the process of separating particles of different sizes. It is accomplished on a screening surface with apertures of a given size and/or shape. The screening surface may be either vibrating or stationary, the latter being used for scalping or wet fine sizing. Vibrating screens include circular motion screens with a sloped surface, to assist transport of the material, and straight motion screens. Coarse screening requires a high amplitude and low frequency, whereas fine screening is performed with a low amplitude and high frequency.

The screening can be performed dry or wet. The ranges of wet and dry application for vibrating screens is shown in Figure 4. With the increasing moisture of raw coal, dry screening is limited today to sizes above 1/4 inch (6 mm). Wet screening dominates, which has increased the use of stationary steeply sloped screens, such as sieve bends, for fine sizing and dewatering. The finer the screen opening, the lower is the capacity for a given surface area; therefore, where a sharp classification of fine material is not required, classifying cyclones that

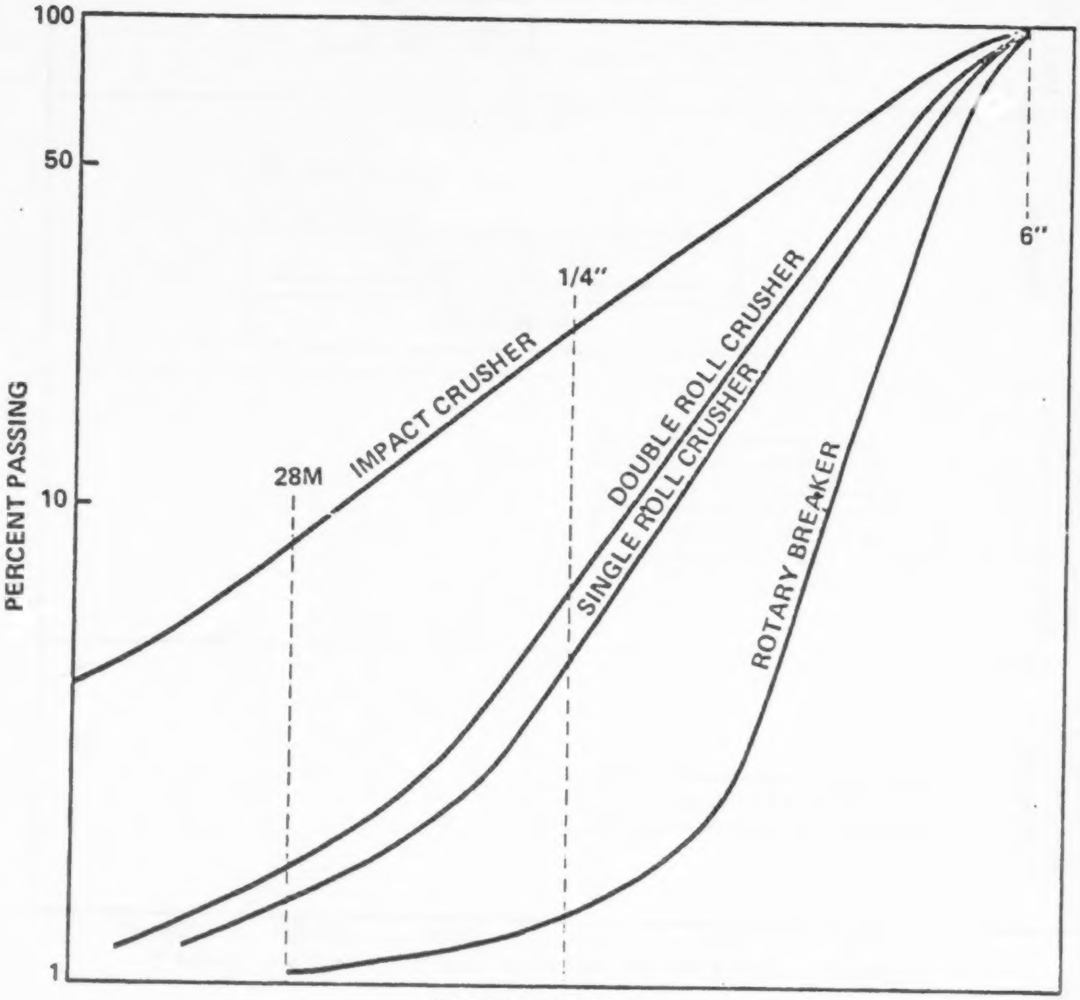

Figure 3. The relative production of fines using different types of crushers for medium-hard coal.

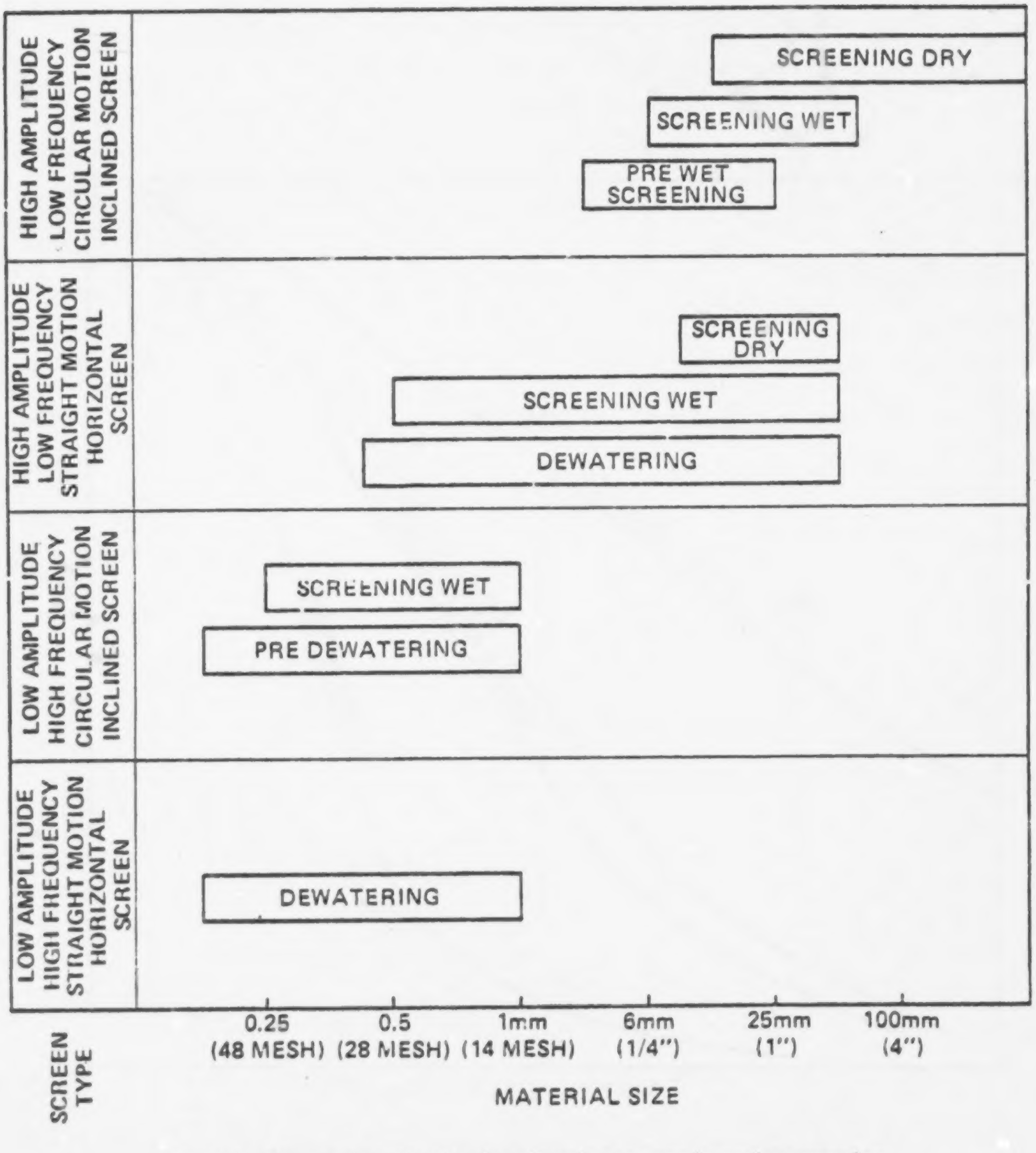

Figure 4. Range of application for vibrating screens in coal preparation.

have a high capacity and relatively low space requirement are preferred.

Separation

Separation divides raw coal into clean coal and refuse, and sometimes additionally middlings, by utilizing differences in physical properties between coal and mineral matter. Specific gravity is the property most commonly used followed by surface wettability for the separation of fine coal. The specific gravity of separation is determined by a sink and float analysis of a given coal. This analysis describes the amount and quality of material between the extremely low and extremely high specific gravity fractions. The separation is considered easy if the amount of material is low in the fraction within ±.10 g/cm^3 of the specific gravity of separation. The separation becomes more difficult as the material to be separated becomes finer. The specific gravity separation technologies commercially available use air, water, or a heavy medium consisting of fine ground magnetite in water. Froth flotation is the only nonspecific gravity separation method for fine coal applied commercially today.

Table 1 lists the application statistics in the United States in the year 1971 and 1973 for various separation methods, indicating that the major portion of the coal is clean in jigs or heavy medium vessels. The trend towards more fine coal

METHOD OF SEPARATION	PERCENTAGE OF COAL PROCESSED	
	1971	1973
JIGS	43	48
TABLES	13	12
LAUNDERS	2	3
HEAVY MEDIUM	33	32
PNEUMATIC	5	0
FLOTATION	3	5

Table 1. —Distribution of the coal cleaned in the United States by method of separation used.

cleaning with froth flotation is already visible and it is interesting to note that dry separation methods for coal are no longer competitive. The ranges of application of separation equipment for wet processes is shown in Figure 5. The ordinate is divided into three size fractions representing common size splits in commercial coal cleaning, and the abscissa shows the difficulty of cleaning expressed by the percentage of "near gravity" material in the ±.10 g/cm^3 fraction. Figure 5 is supplemented by lists of characteristics for various separation equipment for coarse, medium, and fine coal (Tables 2 and 3) as well as performance curves (Figures 6 and 7). Table 2 shows that jigs and heavy-medium vessels are the most commonly used devices for cleaning of coarse coal. The advantages of heavy-medium separators are their ability to accomplish sharp separations even for coals with a high amount of near gravity material and to follow accurate control of the cut point of separation by adjustment for the specific gravity of the medium. Jigs are more sensitive than heavy-medium separators to changes in the feed rate and coal-to-refuse ratio.

Of the remaining equipment listed in Table 2, only hydrocyclones may be considered of value for coarse coal cleaning. Although their performance ranks lower than that of jigs and much below the performance of heavy-medium separators, the use of hydrocyclones as a primary scalping device in conjunction with other equipment, such as heavy-medium vessels, can enhance

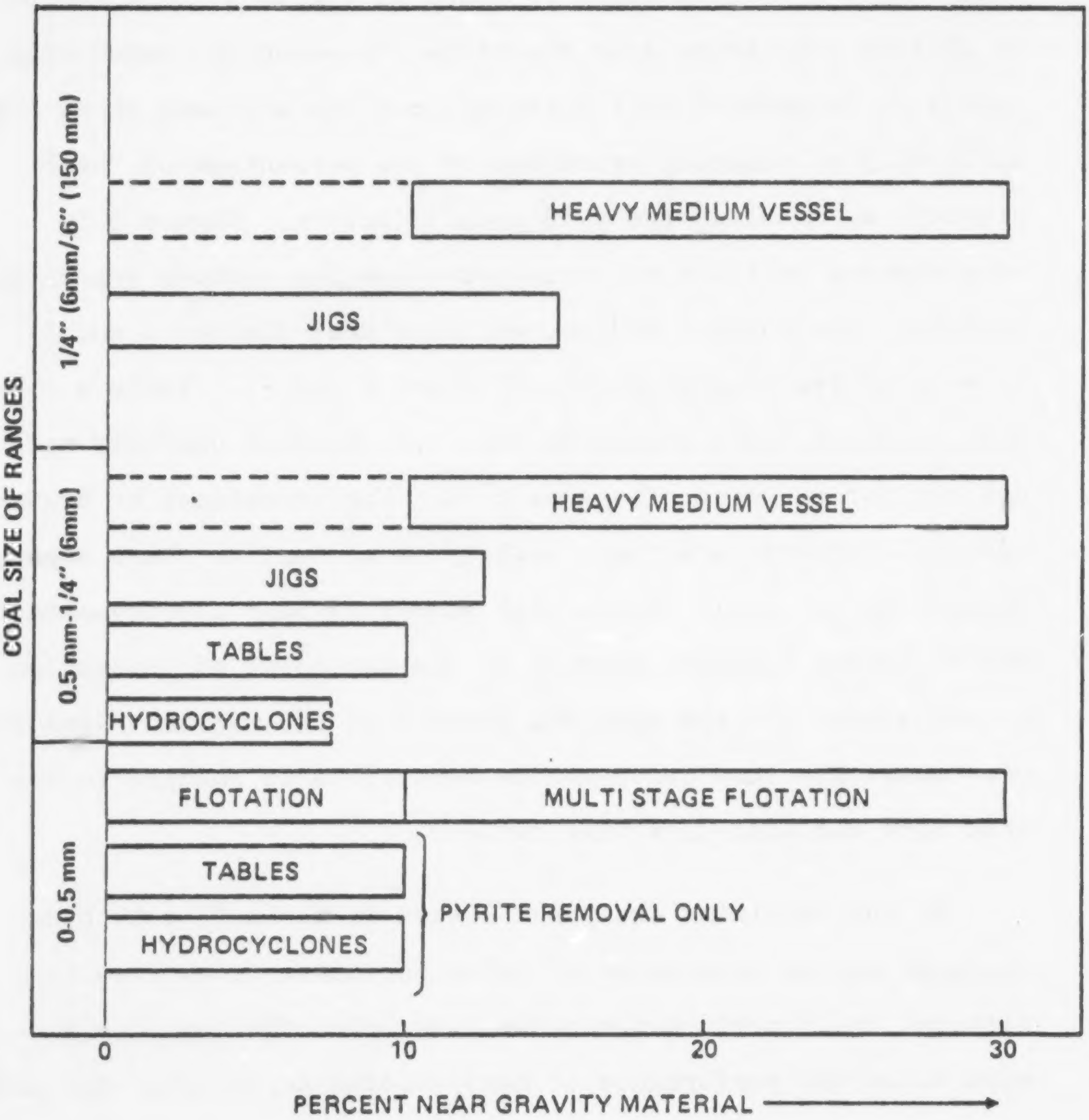

Figure 5. Ranges of application of separation equipment in coal beneficiation.

EQUIPMENT CHARACTERISTICS	JIGS	HEAVY MEDIUM VESSELS	TABLES	HYDRO-CYCLONES	LAUNDERS	PNEUMATIC SEPARATORS
Frequency of usage	Common	Common	Rare	Rare	Rare	Rare
Range of application based on percent of near-gravity material in feed	Up to 10%	Up to 25%	Up to 15%	Up to 7%	Up to 7%	Up to 5%
Common range of specific gravity of separation	Above 1.50	Up to 1.80	1 60 to 1.80	1.40 to 1.80	1.60 to 1.80	1.40 to 1.80
Relative sharpness of separation	Good	Very good	Poor	Fair	Poor	Poor
Relative operating cost	Low	Very high	Low	High	Low	High
Space requirements	High	High	Very High	Low	High	High
Custom built	Yes	Yes	No	No	Yes	Yes
Sensitivity of performance to changes in:						
Feed rate	Yes	No	Yes	Yes	Yes	Yes
Feed size distribution	Yes	No	Yes	Yes	Yes	Yes
Amount of refuse	Yes	No	Yes	Yes	Yes	Yes
Control of cutpoint of separation	Difficult	Easy	Difficult	Difficult	Difficult	Difficult
Relative maintenance costs	Low	High	Low	Fair	Low	Low
General comments	Relatively high capacity per single unit	Require deslimed feed and medium recovery system	Not recommended fo· use with coarse coal	Preferred for primary scalping	Becoming obsolete	Renewed developmental attention is being focused on dry separation methods, but pneumatic methods are not now widely used commercially

*Not including auxiliary equipment such as medium-treatment systems.

Table 2. —Characteristics of equipment used for the separation of coarse coal (+¼").

CHARACTERISTICS	JIGS	HEAVY MEDIUM SEPARATORS	TABLES	HYDRO-CYCLONES	FROTH FLOTATION
Frequency of usage	Rare	Common	Common	Rare	Common
Range of application based on percent of near-gravity material in feed	Up to 10%	Up to 25%	Up to 10%	Up to 5%	(Not applicable)
Common range of specific gravity of separation	Above 1.60	Up to 1.80	1.60 to 1.80	1.40 to 1.80	(Not applicable)
Relative sharpness of separation	Fair	Very good	Fair	Poor	Poor
Relative pyrite removal capability	Good	Good	Good	Good	Poor
Relative operating cost	Fair	Very high	Low	High	Low
Space requirements	High	Low	High	Low	High
Custom built	Yes	No	No	No	Yes
Sensitivity of performance to changes* in:					
Feed rate	High	Low	High	Fair	Low
Feed size distribution	High	Low	High	High	Low
Amount of refuse	High	Low	High	High	Low
Control of cutpoint of separation	Difficult	Easy	Difficult	Difficult	(Not applicable)
Relative maintenance costs	Low	High	Low	Moderate	Low
General comments	Require feldspan bed	Require heavy medium recovery system; relatively high capacity per single unit	Allow isolation of pyrite	Require multiple stages	Poor selectivity of coal from pyrite; require reagents

*Not including auxiliary equipment such as medium-treatment systems

Table 3. —Characteristics of the equipment used for the separation of fine coal and ultrafine coal (−¼").

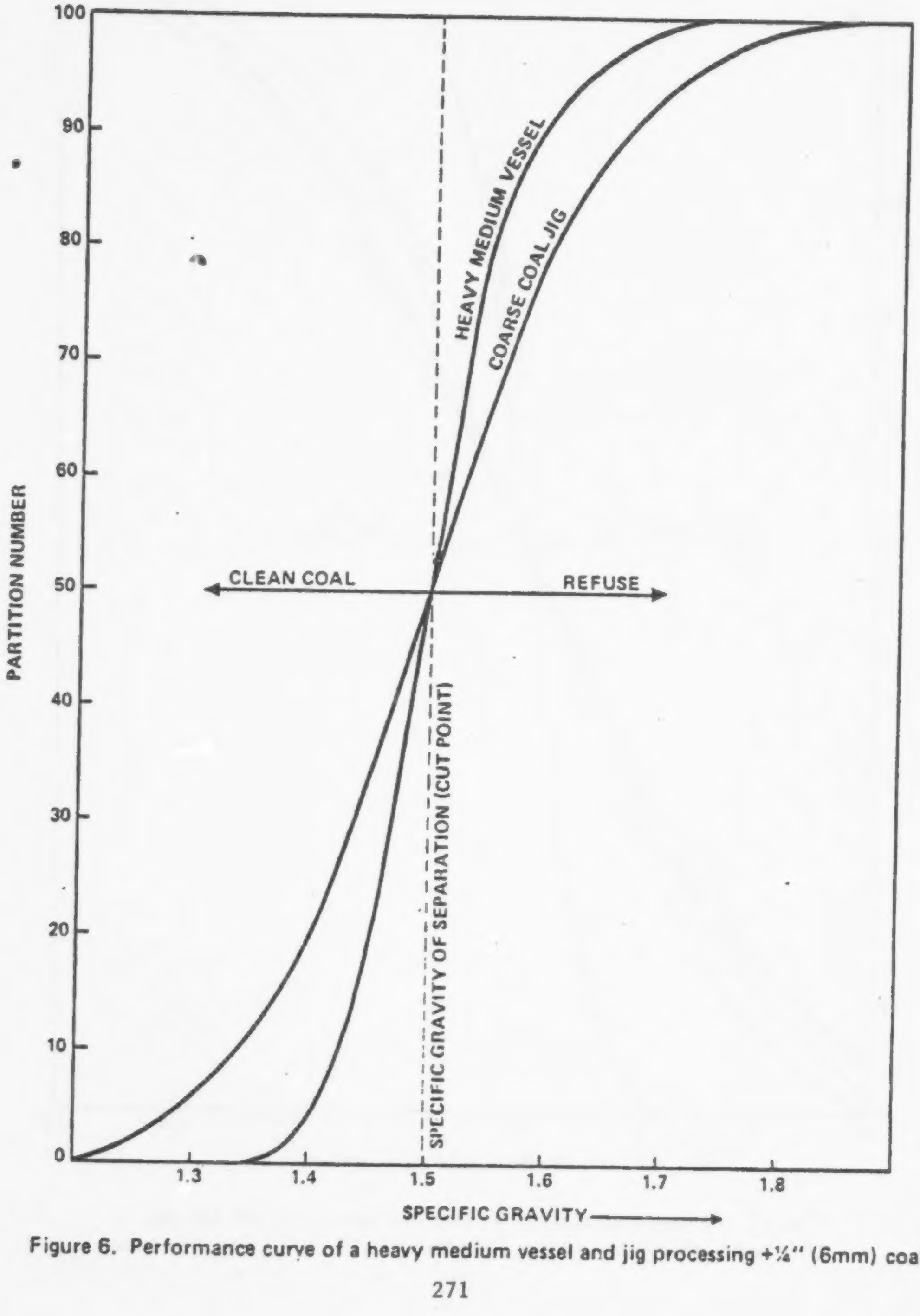

Figure 6. Performance curve of a heavy medium vessel and jig processing +¼" (6mm) coal.

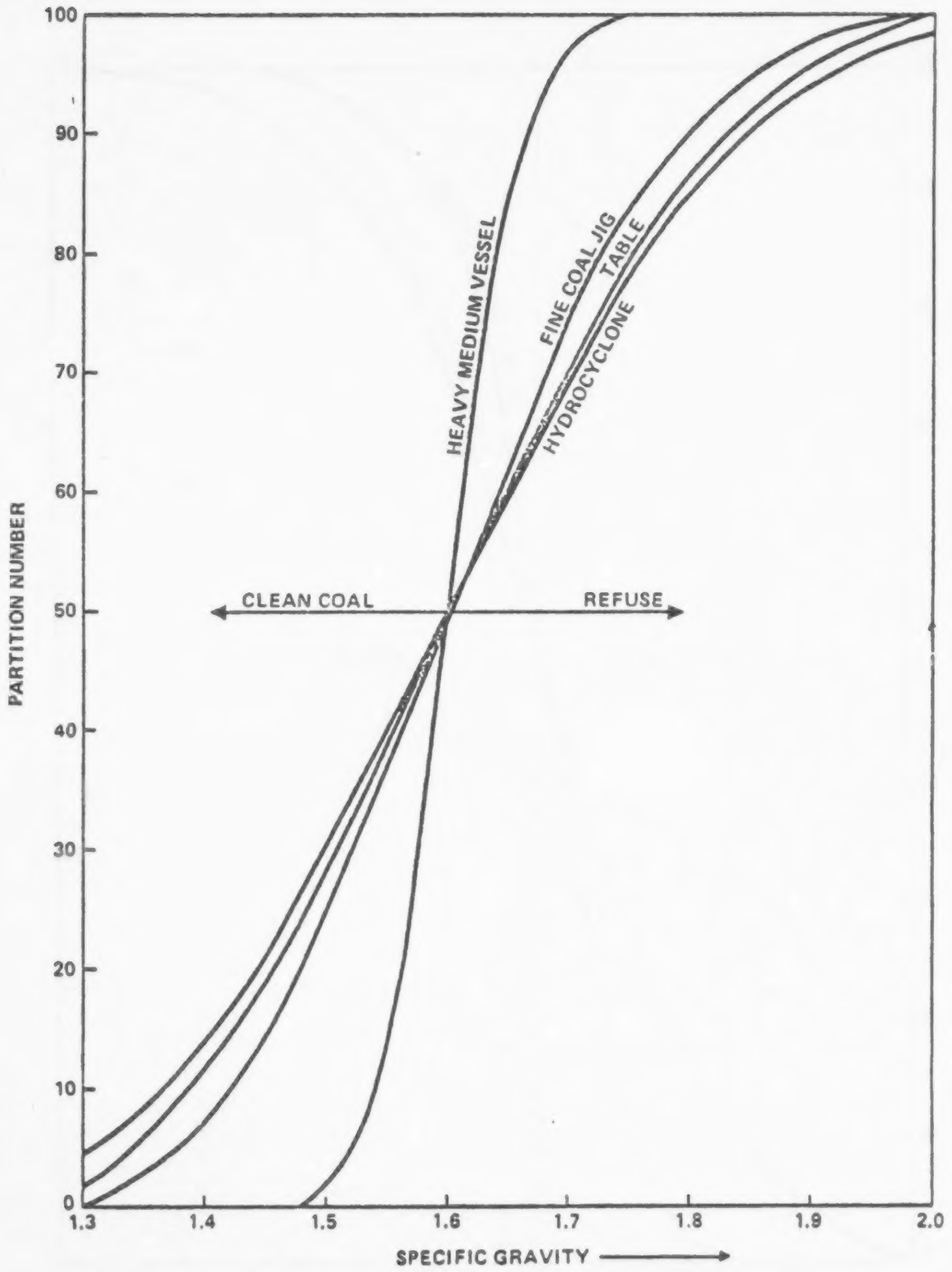

Figure 7. Performance curve of a heavy medium vessel, fine coal jig, table and hydrocyclone treating ¼" (6mm) by 28 mesh (.5mm) fine coal.

the overall economy of the separation system. Figure 6 shows performance curves indicating the difference in performance between a heavy-medium vessel and a jig for coarse coal.

Table 3 lists the characteristics of equipment used for the separation of medium-sized coal and fine coal. Heavy-medium separators, concentrating tables, and froth flotation units are the equipment most commonly in use.

Heavy-medium separators are also the most efficient devices for medium-size coal cleaning, and their application for fine coal cleaning is under investigation. Tables clean medium-size coal at relatively low cost; however, this cleaning has inferior performance characteristics.

Baum-type jigs for medium-size coal have been replaced by higher capacity automatically controlled Batac jigs.

Froth flotation when used under controlled conditions for fine coal amiable to flotation does show good selectivity and good economics for ash rejection. However, since pyrites show similar surface characteristics as coal, froth flotation is not very effective for the removal of pyrites unless practiced in more expensive multiple stages. Reasonable pyrite removal from medium-size and fine coal is possible with hydrocyclones, especially when used in multiple stages or supplemented by other coal cleaning equipment. The space requirements are low, but water pumping adds to the operating cost.

Figure 7 shows the performance curves of the discussed separation equipment for medium-size coal. The characteristics and ranges reported in Tables 2 and 3 suggest a multitude of choices of equipment for the cleaning of coal, which is an indication of the complexity, and sometimes the difficulty, of finding an optimum equipment selection for a given coal.

Dewatering and Drying

With the increasing amount of finer materials, dewatering and drying of the separation products have become a major effort in CPC as indicated by the variety of equipment that has been developed, the latest being pressure filters and centrifuges with high-g forces. Mechanical dewatering is preferred over thermal drying, which is only used where the mechanically dewatered product cannot meet a given moisture specification. Figure 8 shows the various kinds of dewatering equipment, both mechanical and thermal, used with respect to the coal size and the end product moisture desired. The characteristics of this equipment are also reported in Table 4.

Dewatering equipment for the coarse 1/4-inch (6 mm) coal are vibrating screens and sometimes basket-type centrifuges. For 1/4-inch x 28 mesh (6 mm x 0.5 mm) coal, vibrating screens and vibrating basket-type centrifuges are used. For below 28 mesh (0.5 mm) coal, dewatering is accomplsihed by a combination of static thickeners or cyclones with filters or bowl-type centrifuges.

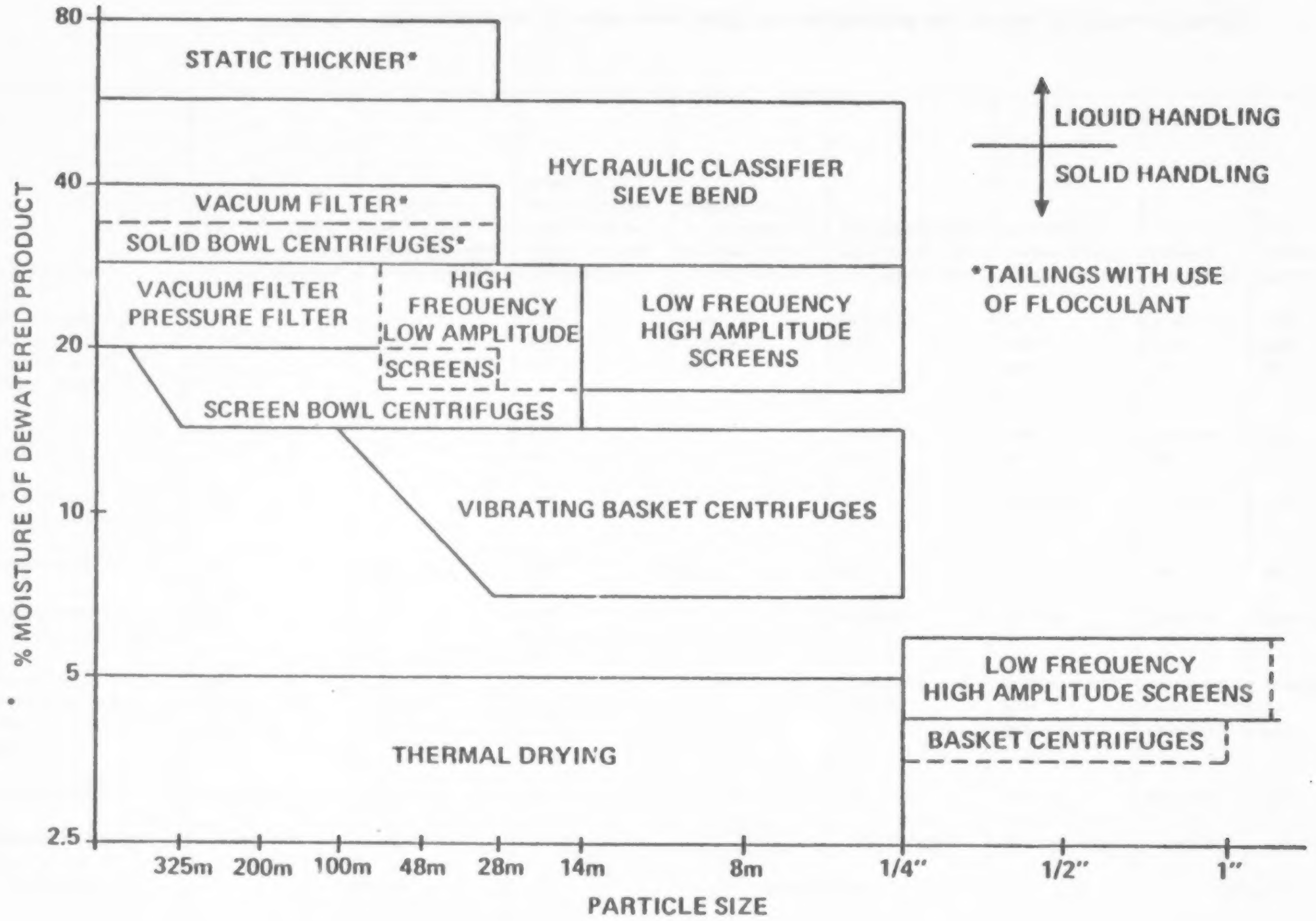

Figure 8. Common ranges of application for coal dewatering equipment.

EQUIPMENT	THICKENERS		CENTRIFUGES			FILTERS			THERMAL DRYERS (PREDOMINANTLY FLUIDIZED BED
CHARACTERISTICS	STATIC	CYCLONES	BASKET	VIBRATING BASKET	SOLID BOWL	SCREEN BOWL	VACUUM	PRESSURE	
Frequency of usage	Common	Common	Low	Common	Low	Low	Common	Rare	Rare
Applications									
Clean coal dewatering	Rare	Common	Common	Common	Rare	Moderate	Common	Rare	Common
Refuse dewatering	Common	Common	Rare	Rare	Moderate	Rare	Rare	Rare	(Not applicable)
Common particle size	29 mesh x 0	¾ inch x 0	1½ x ¾ inch	¾ inch x 28 mesh	28 mesh x 0	14 mesh x 0	28 mesh x 0	28 mesh x 0	1½ inch x 0
Obtainable product moisture content (weight %)	75	70	3 to 4	7 to 9	35 to 40	15 to 20	20 to 30	Under 20	Under 5
Continuous operation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
Sensitivity to varying feed characteristics	Low	Low	Low	Low	High	Moderate	Moderate	Low	Low
Custom designed	Yes	No	No	No	No	No	No	Yes	Yes
Space requirements	Very high	Low	Low	Low	Low	Low	Moderate	High	High
Flocculants, used for dewatering tailings	Yes	No	No	No	Yes	No	Yes	No	(Not applicable)
Relative operating costs	Low	Low	Low	Low	High	High	Low	High	Very high
Relative maintenance costs	Low	Low	Low	Low	Very high	High	Low	Low	High
General comments	Capable of storing slurry; also used for water clarification	Do not produce a clear overflow; low solids recovery	Relatively high basket wear considering low degree of moisture reduction	Product moisture content depends on the amount of slimes in the feed	Can produce clear effluent under controlled conditions	Can be used for desliming froth concentrate	Sensitive to blinding	Require extensive manual labor	Requires efficient dust collection equipment, their operation is governed by numerous environmental and safety regulations

Table 4. —Characteristics of equipment used for mechanical dewatering and thermal drying.

CPC PLANTS

The unit operations can be combined in various manners in coal preparation plants to strike a balance between quality improvement and product recovery. Since raw coal exists in a variety of qualities, CPC plants range from simple one-stage crushing to complex combinations of all unit operations. For simplication, the combinations have been divided into five levels of CPC effort with the lowest as Level 1 and the most complex as Level 5. The definitions of these five levels of CPC are indicated in Table 5 and presented below:

- Level 1 involves no cleaning, but merely the preparation of ROM coal to size specifications.
- Levels 2 and 3 use low efficiency separation devices to process easy-to-clean coal to reject mine dilutions and to free pyrites if present. Level 2 plants clean only the coarse size fraction, whereas Level 3 plants include the cleaning of the medium-size raw coal.
- Levels 4 and 5 make use of high efficiency separation methods to clean all size fractions. Level 5 combines the most sophisticated unit operations to produce a clean coal and a middlings product.

LEVEL	DEGREE OF CLEANING	COMMENT
1	NO CLEANING	SIZING OF EXCELLENT QUALITY RAW COAL
2	MINIMUM CLEANING	SEPARATION OF MINE DILUTIONS FROM COARSE SIZE FRACTIONS OF GOOD QUALITY RAW COAL
3	MODERATE CLEANING	SEPARATION OF MINE DILUTIONS FROM COARSE AND MEDIUM SIZE FRACTIONS OF MEDIUM QUALITY RAW COAL
4	EXTENSIVE CLEANING	CLEANING OF ALL SIZE FRACTIONS OF INFERIOR QUALITY RAW COAL
5	ULTIMATE CLEANING	CLEANING OF ALL SIZE FRACTIONS AND PRODUCTION OF MIDDLINGS FROM LOW QUALITY RAW COAL

Table 5. —The five levels of CPC.

Figures 9 through 13 show block diagrams of CPC plants corresponding to the five levels of CPC effort. Figure 9, a Level 1 effort, shows two process diagrams; one, which can be considered for typical Western subbituminous coal using roll crushers, and the other for a typical Eastern coal using a rotary breaker to reduce the raw coal top size, the latter with a secondary benefit of mine-rock removal. Figure 10 represents a Level 2 effort using a jig to clean the coarse coal after removing medium size and fine coal from the raw coal by dry screening. This operation can rarely fulfill today's coal cleaning requirements. More frequently in use are plants following the flow diagram in Figure 11 (Level 3) where the coarse and medium size coal is cleaned (for example) in jigs, and the fine coal is recovered uncleaned. Figure 12 identifies cleaning systems for all size fractions — a flow diagram that is typical for most CPC plants producing metallurgical grade coal, but that is becoming more and more acceptable for the production of steam coal as well (Level 4).

Finally, a Level 5 CPC effort as diagrammed in Figure 13 uses multiple stages of cleaning to produce a premium clean coal and middlings product. This level of effort is only feasible if the market for middlings can be developed.

Despite the simplified division of CPC into five levels, there are no defined standards for selection of a CPC process

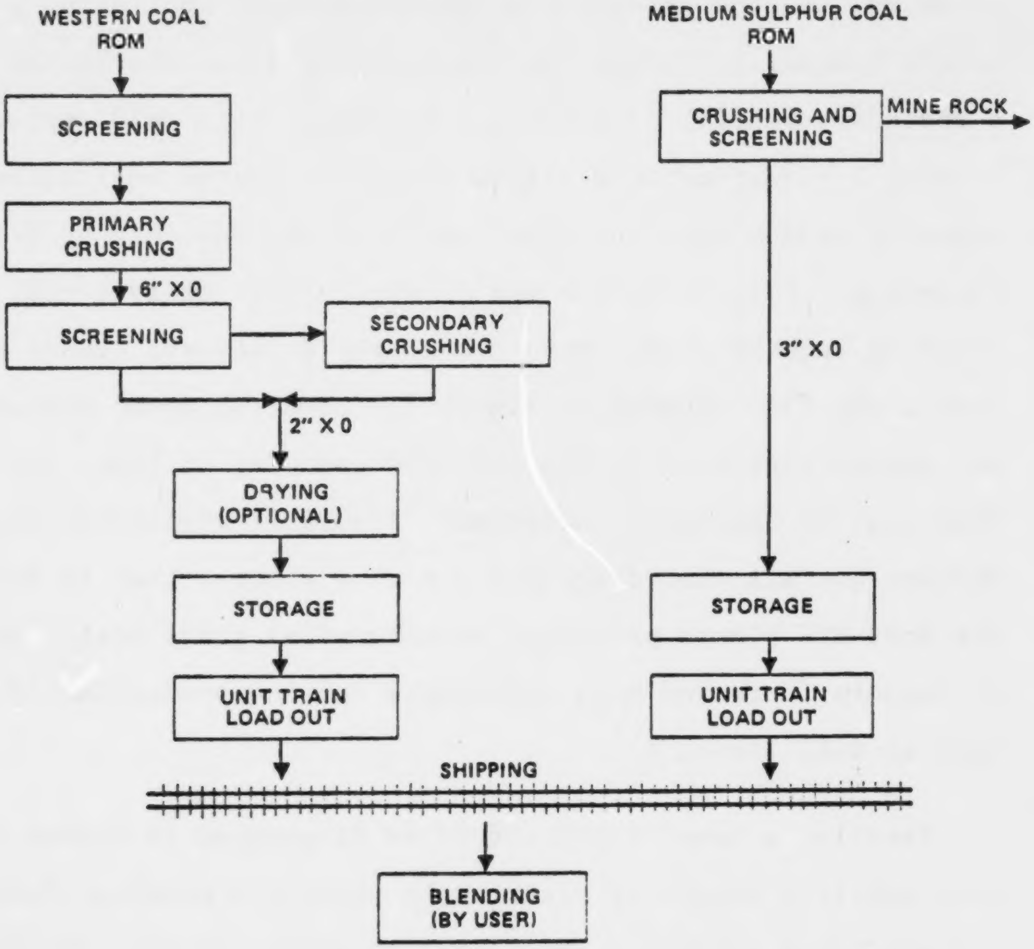
WESTERN COAL ROM
SCREENING
PRIMARY CRUSHING
6" X 0
SCREENING
SECONDARY CRUSHING
2" X 0
DRYING (OPTIONAL)
STORAGE
UNIT TRAIN LOAD OUT
MEDIUM SULPHUR COAL ROM
CRUSHING AND SCREENING
MINE ROCK
3" X 0
STORAGE
UNIT TRAIN LOAD OUT
SHIPPING
BLENDING (BY USER)

Figure 9. Block diagram for Level 1 CPC.

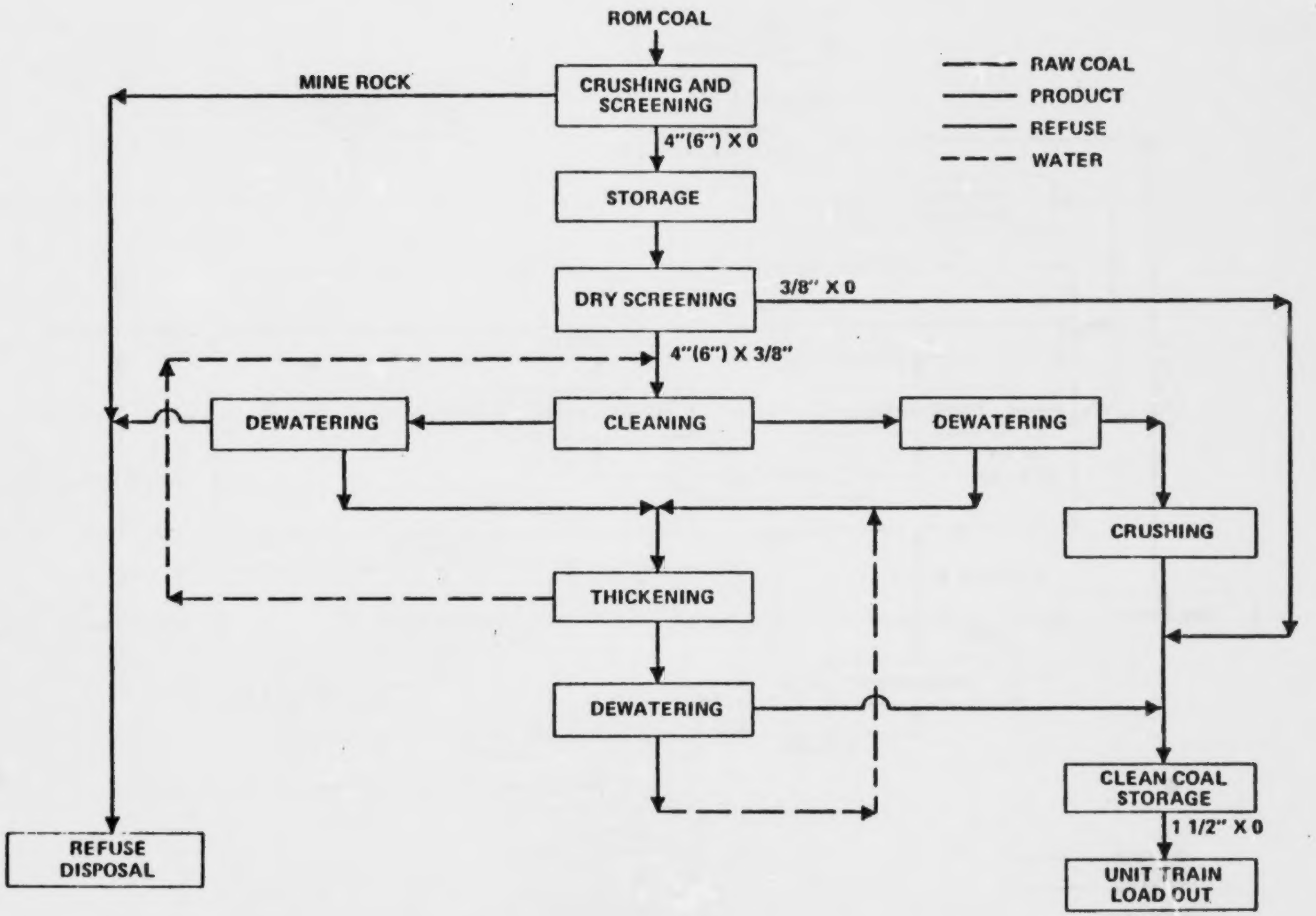
ROM COAL
CRUSHING AND SCREENING
MINE ROCK
4"(6") X 0
STORAGE
DRY SCREENING
3/8" X 0
4"(6") X 3/8"
DEWATERING
CLEANING
DEWATERING
CRUSHING
THICKENING
DEWATERING
CLEAN COAL STORAGE
1 1/2" X 0
UNIT TRAIN LOAD OUT
REFUSE DISPOSAL
RAW COAL
PRODUCT
REFUSE
WATER

Figure 10. Block diagram for Level 2 CPC.

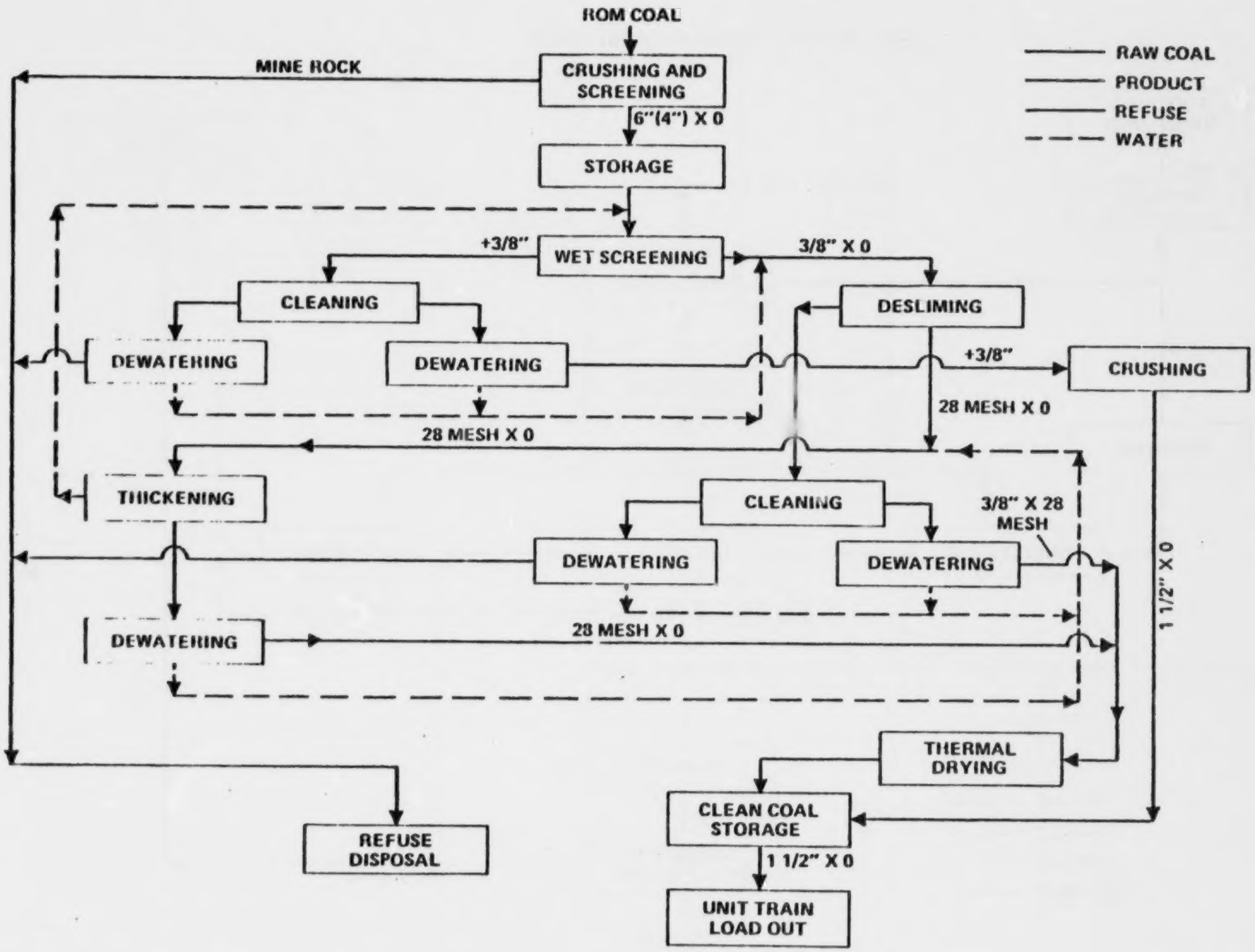
ROM COAL
MINE ROCK
CRUSHING AND SCREENING
6"(4") X 0
STORAGE
WET SCREENING
+3/8"
3/8" X 0
CLEANING
DESLIMING
DEWATERING
DEWATERING
+3/8"
CRUSHING
28 MESH X 0
28 MESH X 0
THICKENING
CLEANING
3/8" X 28 MESH
DEWATERING
DEWATERING
1 1/2" X 0
DEWATERING
28 MESH X 0
THERMAL DRYING
CLEAN COAL STORAGE
1 1/2" X 0
UNIT TRAIN LOAD OUT
REFUSE DISPOSAL
RAW COAL
PRODUCT
REFUSE
WATER

Figure 11. Block diagram for Level 3 CPC.

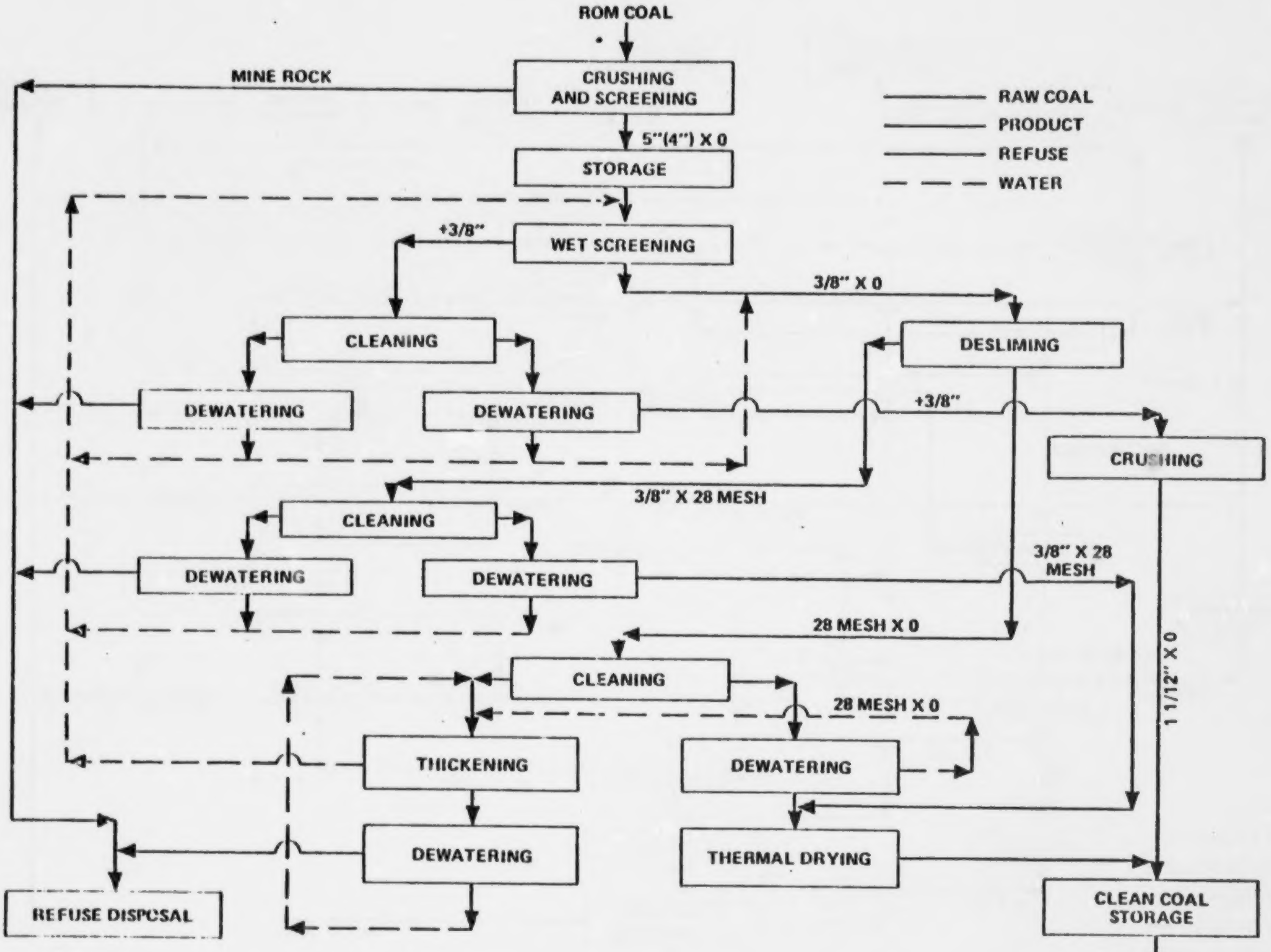
ROM COAL
CRUSHING AND SCREENING
MINE ROCK
5"(4") X 0
STORAGE
RAW COAL
PRODUCT
REFUSE
WATER
+3/8"
WET SCREENING
3/8" X 0
CLEANING
DESLIMING
DEWATERING
DEWATERING
+3/8"
CRUSHING
3/8" X 28 MESH
CLEANING
DEWATERING
DEWATERING
3/8" X 28 MESH
28 MESH X 0
CLEANING
28 MESH X 0
1 1/12" X 0
THICKENING
DEWATERING
DEWATERING
THERMAL DRYING
REFUSE DISPOSAL
CLEAN COAL STORAGE
UNIT TRAIN LOAD OUT

Figure 12. Block diagram for Level 4 CPC.

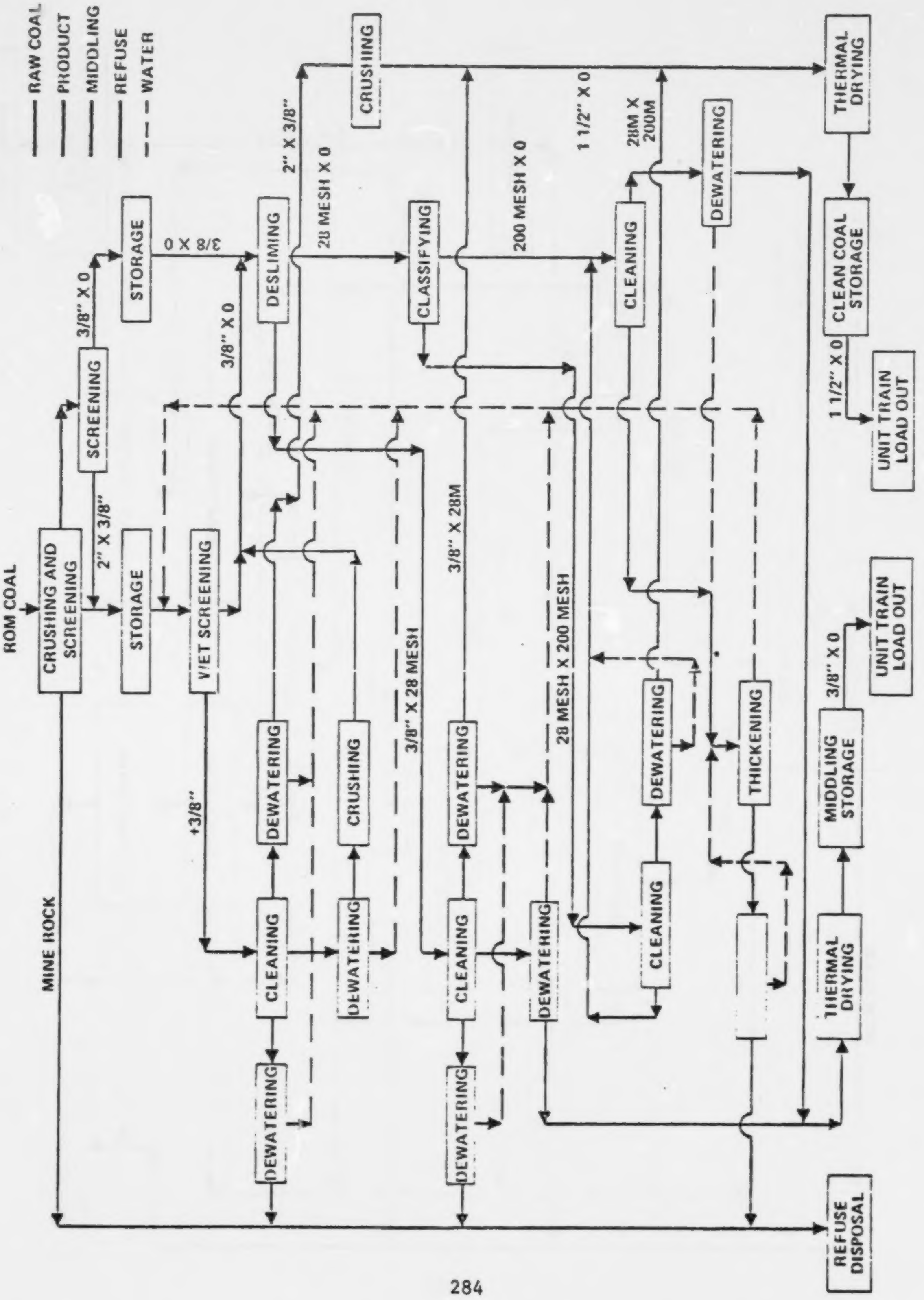
RAW COAL
PRODUCT
MIDDLING
REFUSE
WATER
ROM COAL
CRUSHING AND SCREENING
MINE ROCK
SCREENING
3/8" X 0
STORAGE
3/8 X 0
2" X 3/8"
STORAGE
WET SCREENING
3/8" X 0
DESLIMING
2" X 3/8"
28 MESH X 0
CRUSHING
CRUSHING
+3/8"
CLEANING
DEWATERING
DEWATERING
DEWATERING
CRUSHING
3/8" X 28 MESH
3/8" X 28M
CLASSIFYING
200 MESH X 0
CLEANING
DEWATERING
DEWATERING
DEWATERING
28 MESH X 200 MESH
1 1/2" X 0
28M X 200M
CLEANING
CLEANING
DEWATERING
DEWATERING
THICKENING
THERMAL DRYING
CLEAN COAL STORAGE
1 1/2" X 0
UNIT TRAIN LOAD OUT
THERMAL DRYING
MIDDLING STORAGE
3/8" X 0
UNIT TRAIN LOAD OUT
REFUSE DISPOSAL

Figure 13. Block diagram for Level 5 CPC.

and no standard solution for producing clean coal. Very few CPC plants in the United States are identical even though their block diagrams showing general unit operations may suggest identical treatment of the coals. The equipment selection to perform these unit operations can vary depending on a variety of factors as discussed previously. By substitution and/or addition of equipment, a plant may be converted from one level of CPC to another for reasons such as increased coal desulfurization, improved Btu recovery, or changes in feed characteristics.

For optimal coal cleaning, the raw coal characteristics must be known. Consequently, each coal deposit should be thoroughly explored and characterized, and a mining plan developed that is compatible with effective CPC plant operation. The implementation of such a mining plan can, for example, achieve a more uniform feed to the CPC plant by blending the ROM coals of known characteristics from different mining sections.

ECONOMIC OVERVIEW

A process flow diagram was prepared for each of the five levels of CPC based on specific coals. The coals were selected based on their reserves and on their sulfur reduction potential to meet a product specification that would allow the burning of the coal without releasing more than 1.2 lb $SO_2/10^6$ Btu. The flow diagrams and the equipment selection were prepared on the basis of 1,000 TPH or 3.25 x 10^6 TPY of marketable products. Two coals – one with high sulfur and one with low sulfur coal so that the two coals can be blended to meet product specifications – were in the Level 1 effort. The coal selected in the order of levels of CPC are: Rosebud coal and Illinois No. 6 for Level 1; Cedar Grove coal for Level 2; Montrose coal for Level 3; lower Kittaning coal for Level 4; and upper Freeport coal for Level 5.

The flow diagrams served as the basis to estimate capital and operating costs. Table 6 shows the summary of the capital cost data in 1977 dollars, and this table is supplemented by a detailed cost breakdown of the direct field costs in Table 7. It is interesting to note that a substantial part of the direct field costs is attributable to environmental equipment and materials as shown in Table 7a. For the different levels of CPC, the environmental-related direct capital field costs range from 15.9 to 7.6 percent. The operating requirements and operating costs for the corresponding levels of CPC are shown in Table 8, with a summary of the processing costs given in Table 9.

The processing costs are only part of the cost entering into the calculation of final fuel cost. The cost of the refuse, which is a function of the product recovery, must be recognized. Figure 14 expresses graphically the composition of the final fuel cost at the CPC plant boundary.

	CAPITAL COSTS (IN THOUSANDS OF DOLLARS)					
	CASE 1.1[a]	CASE 1.2	CASE 2	CASE 3	CASE 4	CASE 5
Coal cleaning facility	1,460	1,110	3,640	8,490	10,260	16,590
Ancillary facilities	2,610	2,510	4,150	4,150	4,260	7,290
Environmental equipment and materials	770	540	890	1,270	2,170	1,980
Direct field cost	4,840	4,160	8,680	13,910	16,690	25,860
Indirect field cost	200	160	290	1,170	1,250	2,250
Total field cost	5,040	4,320	8,970	15,080	17,940	28,110
Engineering services	600	520	1,080	1,810	2,150	3,370
Construction cost	5,640	4,840	10,050	16,890	20,090	31,480
Allowance for uncertainty	1,160	960	2,050	3,410	4,010	6,320
Total Construction Cost	6,800	5,800	12,100	20,300	24,100	37,800
Client engineering[c]	204	174	363	609	723	1,134
Environmental impact statement[d]	102	87	182	304	362	567
Working capital	122	100	146	187	272	385
Construction interest	1,479	1,253	1,960	4,385	5,205	8,165
Land[b]	150	150	225	330	900	600
Total Capital Cost	8,857	7,564	14,976	26,115	31,562	48,651

[a] An additional construction cost of $6.9 million for an optional thermal dryer is not included in these figures for Case 1.1.

[b] A land cost of $3,000 per acre was used in calculating Land Cost.

[c] 3% of Construction Cost.

[d] 1.5% of Construction Cost.

Table 6. —Conceptual estimate capital cost summary.

COST ITEM	CAPITAL COSTS (IN THOUSANDS OF DOLLARS)					
	CASE 1.1*	CASE 1.2	CASE 2	CASE 3	CASE 4	CASE 5
Coal Cleaning Facility	1,460	1,110	3,640	8,490	10,260	16,590
Site preparation	100	100	120	120	220	220
Concrete	40	40	170	170	350	400
Steel and building services	20	20	320	320	2,380	3,130
Mechanical	390	440	1,730	1,220	5,210	9,200
Conveyors	660	330	720	5,190	810	1,420
Piping and Instrumentation	90	70	220	430	500	870
Electrical	160	110	360	670	790	1,350
Ancillary Facilities	2,610	2,510	4,150	4,150	4,260	7,290
Yard facility	200	200	260	260	370	370
Transportation and mobile equipment	730	730	730	730	730	730
Storage and loadout	1,640	1,540	3,120	3,120	3,120	6,110
Service buildings	40	40	40	40	40	80
Enviromental Equipment and Materials	770	540	890	1,270	2,170	1,980
Dust collection	520	290	550	445	590	740
Noise abatement	30	30	70	175	270	270
Refuse disposal area	220	220	270	650	1,310	970
Total Direct Field Cost	4,840	4,160	8,680	13,910	16,690	25,860

*An additional direct field cost of 4.17 million dollars for an optional thermal dryer is not included in these figures for Case 1.1.

Table 7. —Details of conceptual cost estimates.

CASE	ENVIRONMENTAL-RELATED DIRECT CAPITAL FIELD COSTS ($1000's)	DIRECT FIELD COSTS RELATED TO ENVIRONMENTAL CONTROLS
1.1[a]	770	15.9%
1.2	540	13.0%
2	890	10.3%
3	1,270	9.1%
4	2,170[b]	13.0%
5	1,980	7.6%

[a] without optional thermal drying

[b] high reject disposal

Table 7a. —Fraction of direct field costs devoted to environmental control equipment in the CPC plants.

	Case 1.1	Case 1.2	Case 2	Case 3	Case 4	Case 5
Plant Construction Cost	$6,800,000	$5,800,000	$12,100,000	$20,300,000	$24,100,000	$37 800,000
Installed Equipment Cost	1,850,000	1,270,000	3,650,000	7,600,000	8,180,000	13,850,000
Processing Costs	0.584	0.518	0.916	1.396	1.834	2.825
Return on Investment, 30% before taxes	0.245	0.209	0.408	0.723	0.874	1.347
Total ($/ton dry product)	0.829	0.727	1.324	2.119	2.708	4.172
Processing Costs	0.026	0.019	0.036	0.053	0.064	0.097
Return on Investment, 30% before taxes	0.011	0.008	0.016	0.028	0.031	0.046
Total ($ MMBtu)	0.037	0.027	0.052	0.081	0.095	0.143

	ANNUAL COST ($)					
Direct Costs						
Labor						
Operating Labor and Supervision, $87/man shift	240,555	240,555	288,666	312,678	505,122	563,320
Maintenance Labor and Supervision, $87/man shift	96,222	96,222	144,333	144,420	240,555	360,789
Total Labor and Supervision	336,777	336,777	433,000	457,420	745,677	914,109
Operating Utility and Consumables						
Magnetite, $65/ton	–	–	–	-	97,240	343,770
Flocculant, $2/lb	–	–	–	4,290	29,030	62,776
Power, $0.021/kWh	52,080	27,300	78,170	131,313	194,880	340,704
Water, $0.15 M gal	-		2,047	1,755	7,459	9,506
Operating Supplies, 10% of Labor	33,678	33,678	43,300	45,710	74,568	91,411
Maintenance, Material, Supply, and Equipment Replacement, 7% of IEC	129,500	88,900	255,500	532,000	572,600	969,500
Sampling and Analysis, $15/hr	48,750	48,750	48,750	48,750	48,750	48,750
Total Utilities and Consumables	264,008	198,628	428,767	763,818	1,024,527	1,866,367
Total Direct Cost	600,785	535,405	861,767	1,220,918	1,770,204	2,780,476
Indirect Costs						
Plant Overhead, 50% of Labor	168,388	168,388	216,500	228,550	372,839	457,054
Administration and Corporate Expenses, 10% of Labor	33,678	33,678	43,300	45,710	74,568	91,411
Taxes and Insurance, 1.5% of Plant Cost	102,000	87,000	181,500	304,500	361,500	567,465
Total Indirect Costs	304,066	289,066	441,300	578,760	808,907	1,115,930
Capital Related Costs						
Debt Interest Expense (70% @ 9%)	428,400	365,400	762,300	1,215,900	1,518,300	2,381,400
Construction Interest Expense, 9% of Interest During Construction	38,500	33,823	52,925	84,418	105,413	192,893
Working Capital Interest, 9%	91,517	87,746	121,748	146,268	223,465	308,310
Depreciation 20 years (straight line)	435,350	370,700	737,550	1,289,278	1,533,100	2,402,525
Total Capital Related Costs	993,767	857,669	1,674,523	2,735,864	3,380,276	5,285,128
TOTAL PROCESSING COST	1,898,618	1,682,140	2,977,590	4,535,542	5,959,387	9,181,534

Note. Plant Capacity. 1000 TPH; 3.25 million tons per year. Operating Data: 250 days per year, 13 hours per day.

Table 8. —Analysis of annual coal processing.

CASE	1.1[b]	1.2	2	3	4	5
COAL	MONTANA (ROSEBUD)	ILLINOIS (NO. 6)	W. VIRGINIA (CEDAR GROVE)	COLORADO (MONTROSE CITY)	PENNSYLVANIA (LOWER KITTANNING)	PENNSYLVANIA (UPPER FREEPORT)
Plant Construction Cost	6,800,000	5,800,000	12,100,000	20,300,000	24,100,000	37,800,000
Pre-construction and Owners Costs	1,907,000	1,614,000	2,651,000	5,485,559	6,562,000	10,250,500
Total Depreciable Capital Cost	8,707,000	7,414,000	14,751,000	25,785,559	30,662,000	48,050,500
Land Cost	150,000	150,000	225,000	330,000	900,000	600,000
Total Capital Costs	8,857,000	7,564,000	14,976,000	26,115,559	31,562,000	48,650,500
Annual Costs						
Operating and Maintenance	904,851	824,471	1,303,067	1,799,678	2,579,111	3,896,406
Capital-Related[c]	993,767	857,669	1,674,523	2,735,864	3,380,276	5,285,128
Total Annual Costs	1,898,618	1,682,140	2,977,596	4,535,542	5,959,387	9,181,534
Return on Investment[d]	797,130	680,760	1,327,590	2,350,400	2,840,580	4,378,545
Coal Processing Costs[e]						
\$/ton dry product	0.584	0.518	0.916	1.396	1.834	2.825
\$/10^6 Btu dry product	0.026	0.019	0.036	0.053	0.064	0.097
Return on Investment						
\$/ton dry product	0.245	0.209	0.408	0.723	0.874	1.347
\$/10^6 Btu dry product	0.011	0.008	0.016	0.028	0.031	0.046
Total Costs						
\$/ton dry product	0.829	0.727	1.324	2.119	2.708	4.172
\$/10^6 Btu dry product	0.037	0.027	0.052	0.081	0.095	0.143

[a] Corresponds to 3.25 million tons per year (dry) at 250 thirteen-hour annual operating days.
[b] Excluding thermal drying option which would add \$0.45 per ton dry product to the processing cost, and \$6,900,000 to the capital investment.
[c] Calculated at a 7:3 debt/equity ratio repaying debt with 9% 20-year bonds.
[d] Calculated on equity with a before tax return of 30% with no discounting.
[e] All costs for Case 5 reflect the combined middlings and clean coal products. The separation of these costs will depend on market conditions.

Table 9. —Operating cost summary.

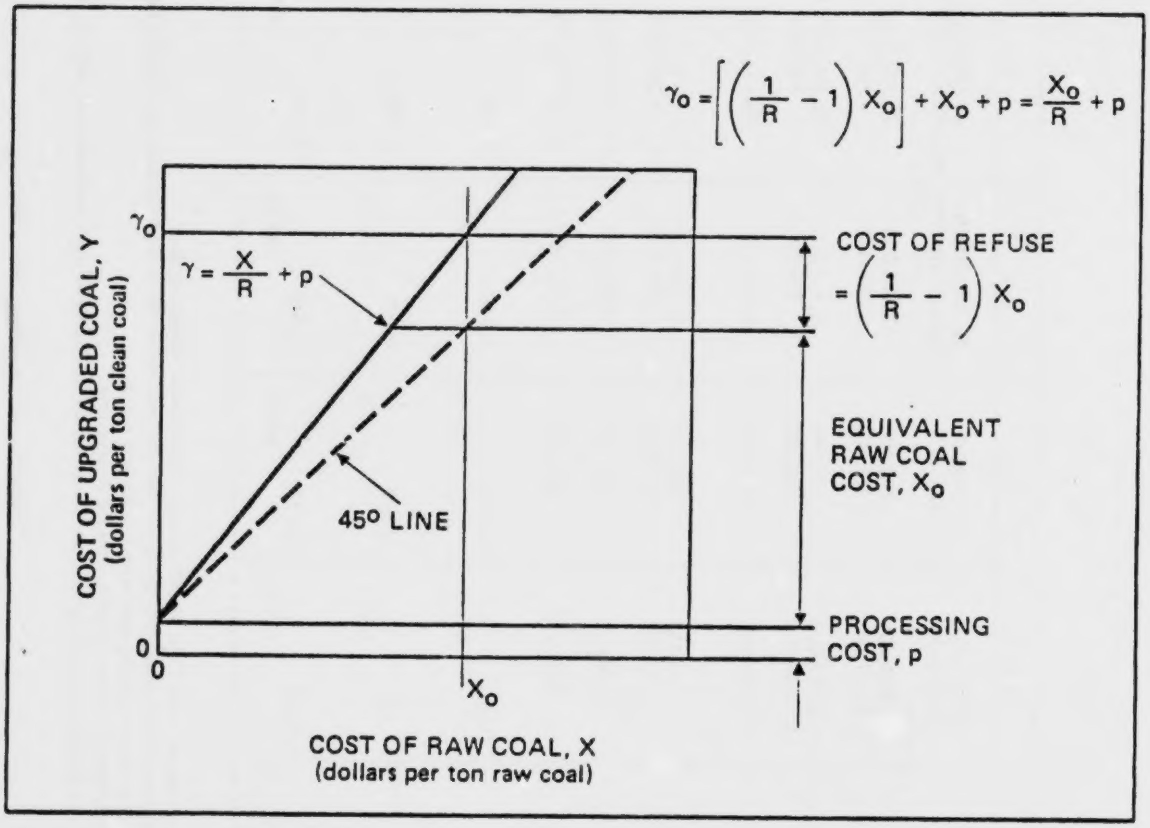
$\gamma_o = \left[\left(\frac{1}{R} - 1\right) X_o\right] + X_o + p = \frac{X_o}{R} + p$
γ_o
$\gamma = \frac{X}{R} + p$
45° LINE
COST OF REFUSE
$= \left(\frac{1}{R} - 1\right) X_o$
EQUIVALENT RAW COAL COST, X_o
PROCESSING COST, p
0
0
X_o
COST OF UPGRADED COAL, Y (dollars per ton clean coal)
COST OF RAW COAL, X (dollars per ton raw coal)

Figure 14. The cost components of the total cost of product coal at the CPC plant boundary.

As can be seen, the total cost is very sensitive to the amount of refuse, especially when the raw coal cost is high. This is clearly demonstrated in Figure 15, which shows that even though the processing cost for Case 4 is lower than for Case 5, the final fuel cost becomes higher as the cost of the raw coal increases. The reason for this is that the coal chosen for Level 4 shows a low weight recovery of 68.6 percent versus the 76.1 percent weight recovery of marketable product for the Level 5 operation. The weight recovery, Btu recovery, as well as other performance data for the five levels of CPC are shown in Table 10.

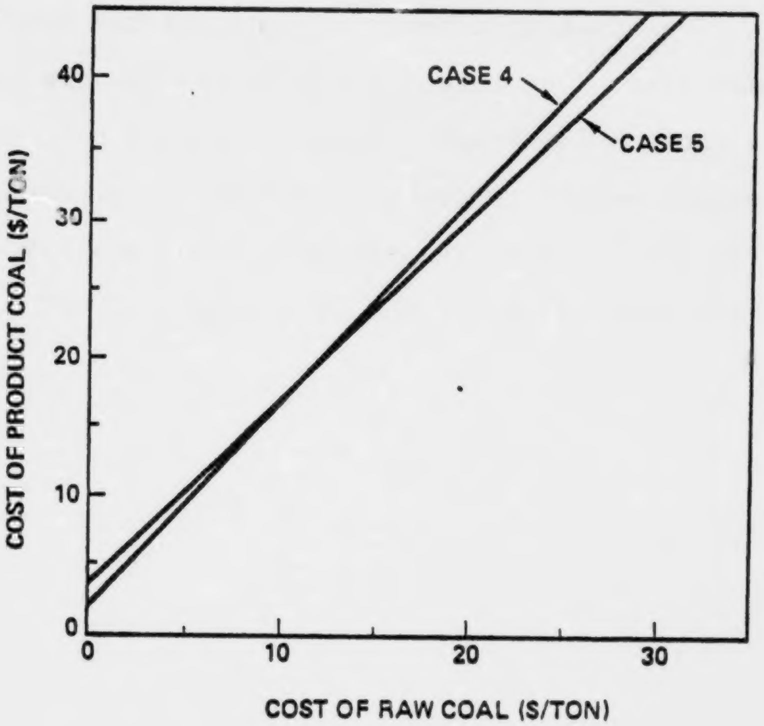

Figure 15. Clean coal effective cost on a weight basis compared to raw coal costs for cases 4 and 5.

CPC LEVEL COAL	CASE 1.1 MONTANA	CASE 1.2 ILLINOIS	CASE 2 WEST VIRGINIA	CASE 3 COLORADO	CASE 4 PENNSYLVANIA	CASE 5 PENNSYLVANIA
Raw Coal						
Heating Value	11,709	13,314	11,810	11,790	12,830	11,486
% Sulfur (Pyritic)	0.23	0.92	0.11	0.25	2.19	2.79
Total	0.70	2.69	0.81	0.80	2.77	3.40
Ash %	8.8	7.5	22.7	19.4	13.0	23.4
Average Moisture %	24.1	4.1	5.0	6.0	1.3	5.0
lb $SO_2/10^6$ Btu	1.20	4.04	1.37	1.36	4.32	5.92
Product Coal						
Heating Value	11,709	13,314	12,655	13,120	14,250	14,608 12,342
% Sulfur (Pyritic)	0.23	0.92	0.03	0.19	0.22	0.22 1.56
Total	0.70	2.69	0.75	0.73	0.80	0.83 2.17
Ash %	8.8	7.5	17.0	10.5	4.7	3.3 17.5
Moisture %	24.1 (13.6)	4.1	6.5	4.0	6.0	6.0 6.0
lb $SO_2/10^6$ Btu	1.20	4.04	1.19	1.11	1.12	1.14 3.52
Performance						
% Weight Recovery	100 (97.6)	100	90.9	84.7	68.6	48.1 28.0
% Btu Recovery	100 (97.6)	100	97.4	94.3	76.2	61.2 30.1
% Sulfur Reduction	–	–	7.4	8.8	71.1	75.6 36.2
Refuse						
Ash %	–	–	79.6	70.6	31.2	72.1
% Sulfur (Pyritic)	–	–	0.67	0.64	6.52	9.58
Total	–	–	1.40	1.18	7.1	10.19
Btu	–	–	3,370	4,140	9,837	3,996

Table 10. —Performance summary for the six CPC systems designed.

SUMMARY

Coal preparation and cleaning (CPC) processes include comminution, classification, separation, dewatering, and drying. Run-of-mine (ROM) coal is processed by all or any combination of these processes on its way to the consumer. Each process is performed in unit operations that may use various types of equipment and process principles. The unit operations are combined in CPC plants, in sequences depending on the raw coal characteristics and the extent of CPC effort required to produce a marketable product or products. The objective is to strike an economic balance between high-Btu recovery and reduced ash or sulfur levels. Five levels of CPC efforts have been defined, each of which (when used with the appropriate raw coal) can produce marketable products, i.e., at least one product that would release not more than 1.2 pounds of sulfur per million Btu when combusted.

The add-on costs to ROM coal have been calculated on the basis of the processing of different coals, at least one for each level of effort. These costs include capital cost, the cost of refuse disposal, and the cost of environmental controls. An equation has been developed that allows calculation of the total cost of upgraded coal at the CPC plant boundaries, including the raw coal cost.

This paper shows that a variety of physical CPC technologies are available to upgrade ROM coal. Since the objectives and degree of CPC vary from case to case and with changing market requirements, standardization of CPC is very difficult. The emphasis on pyrite removal, which necessitates the treatment of finer material, has made CPC application more complex.

The economic evaluations show the sensitivity of the final product cost to the product weight recovery. This important factor is often neglected in the search for low-cost methods to improve coal quality. With rising coal costs, product recovery must be a dominant factor in any CPC effort selection. Likewise, emphasis should be made to operate the CPC plants with maximum efficiency.

ACKNOWLEDGMENTS

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OVERCOMING THE BARRIERS TO INVESTMENT IN PHYSICAL COAL CLEANING FOR SO_2 EMISSIONS CONTROL

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ABSTRACT

Teknekron, like others, has found that physical coal cleaning in many cases could be the least-cost strategy for achieving dramatic reductions in sulfur dioxide emissions. But right now physical coal cleaning for SO_2 emission control is little more than an intriguing idea. It has yet to be implemented in any substantial way.

So how do we get from here to there? How do we encourage the use of physical coal cleaning (PCC) in those situations where its economic and environmental payoff can be predicted with reasonable confidence?

The key is to take a real-world approach, by looking at coal cleaning from the point of view of the potential investor. In other words, getting from here to there demands more than theoretical studies of the engineering and environmental benefits of PCC. It means recognizing that the people providing the risk capital for PCC face a number of formidable investment barriers.

These investment barriers--and the strategies for overcoming them--are the subject of this Teknekron paper. We begin by summarizing the barriers Teknekron has identified. Then we turn briefly to a few of our engineering calculations showing that PCC in certain circumstances can be the least-cost SO_2 and particulate compliance option. Finally, we proceed to a fuller discussion of the barrier analysis and explore the strategies that Teknekron believes would lead to wider investment in PCC.

The Barriers: A Summary

After interviewing bankers and a variety of potential coal-cleaning investors--large and small coal companies, electric utilities, and other current and would-be industrial coal users--and after considering a wide range of possible investment barriers (institutional, economic, social, regulatory, legislative, financial, legal, and contractual), Teknekron has concluded that eight factors in particular are currently inhibiting the widespread adoption of PCC. Some of these barriers constrain only certain types of investors. Others appear relevant to all of them.

The first three barriers have to do with information or data deficiency:

- First, in general, none of the potential investors are aware of the wide range of benefits and costs that might accrue from different applications of PCC.
- Second, electric utilities and the various public utility commissions generally know relatively little about developments in PCC technology and about the possible applications of these developments.
- Third, some potential investors with whom Teknekron has spoken say that the engineering and economic studies performed to date are inadequate. In other words, these studies are not "investment grade" analyses. They lack data from full-scale PCC demonstrations, and they fail to examine the sensitivity of PCC economics to such things as the price of coal, the fraction of pyritic sulfur in the coal, transport costs, boiler or contract lives, different SO_2 standards, and type of investor.

The next two barriers are essentially institutional in nature:

- Whereas relatively small coal companies may control significant quantities of cleanable reserves, these companies may be unable to bring their coals into the marketplace without help in establishing institutional arrangements for the sharing of PCC plants.
- Furthermore, potential nonutility coal consumers see the environmental, logistical, and institutional costs of burning coal as prohibitive under most circumstances.

The next barrier involves two regulatory constraints:

- Despite provisions in the 1977 amendments to the Clean Air Act that permit credit for precombustion sulfur removal, coal cleaning (unlike flue gas desulfurization) is not considered a pollution control investment by the Internal Revenue Service. Nor does it qualify for investment tax credits. What this means is that PCC does not enjoy certain tax and financing advantages afforded FGD investment.

The last two barriers involve uncertaintities about government action:

- First, potential investors are unsure about the ultimate costs of the air and water quality regulations that will be applied to PCC plants themselves.
- Second, potential investors are inhibited by enormous uncertainty surrounding several issues related to EPA activity--the enforcement and enforceability of State Implementation Plans, the feasibility of continued noncompliance, decisions regarding quadrennial review of standards, definitions of Best Available Control Technology for PSD applications, decisions on offset policies, the rate at which state standards

may become more stringent, and the ultimate stringency of SO_2 standards for coal-fired boilers.

Teknekron examined many other possible barriers to coal cleaning investment, including barriers that have been suggested by others from time to time. For example, we considered the concern that existing coal supply contracts lack price adjustment clauses, and we considered the claim that certain types of investors will reject coal cleaning out of hand no matter what the state of the PCC investment environment may be. No evidence emerged, however, to suggest that any of these other factors were significant.

Examples of PCC as the Least-Cost Option

Before discussing the investment barriers in more detail, it seems appropriate to look at a few cases where Teknekron's engineering calculations show PCC to be the least-cost strategy for complying with SO_2 and particulate emission limitations.

As a first example, consider a hypothetical 300 MW coal-fired power boiler located in the vicinity of Harrisburg, Pennsylvania, where there is a relatively strict state SO_2 limit of 2.0 pounds per million Btu and a particulate limit of 0.2 pound per million Btu. If we assume current f.o.b. mine prices, current average rail tariffs, current cost data for new scrubbers, and a coal-cleaning charge of $2.00 per raw ton with 88 percent Btu recovery, we get the results shown in table 1.

The options shown in the table are ranked in order of increasing total cost of operating the boiler in compliance with emission constraints. By total cost we mean the sum of the delivered cost of the coal plus the annualized pollution control investment and operating costs. It's this "as burned," or total

Table 1

Costs of Alternative Strategies for Meeting Emission Limits of $2.0\ \mathrm{lb}/10^6$ Btu SO_2, $0.2\ \mathrm{lb}/10^6$ Btu Particulates (Southeast Pennsylvania Location)

Coal Source, Type	Delivered Coal Cost ($¢/10^6$ Btu)	Cost of ESP ($¢/10^6$ Btu)	Cost of FGD ($¢/10^6$ Btu)	Total Cost ($¢/10^6$ Btu)
Pennsylvania, cleaned	129	20.9	-	150
West Virginia, uncleaned	132	23.6	-	156
Pennsylvania, uncleaned	108	18.1	45	171

effective cost, that is the relevant measure to use when comparing different compliance strategies from the utility's point of view.

In this case we see that, given our assumptions, the cleaned-coal option is slightly cheaper than the option of buying higher quality, more distant, low-sulfur West Virginia coal and considerably cheaper than the option of partially scrubbing the more local coal.

As a second example, consider a new 500 MW coal-fired unit located in the central part of Ohio and subject to the new source standards of 1.2 pounds of SO_2 and 0.1 pound of particulates per million Btu of boiler heat input. Using the same assumptions as in the previous example, we compare three different compliance strategies, as shown in table 2. Here, importing high quality, cleaned Central Appalachian coal is cheaper than either importing low-sulfur, complying western coal or scrubbing "local" coal. Note, by the way, the importance of considering the costs of particulate controls in these types of calculations, especially when western coals with relatively low ash conductivity are being compared with eastern and midwestern competitors.

These examples illustrate the types of engineering calculations we have carried out for many different situations. While several of the assumptions behind the calculations are subject to argument, of course, the relevant point in the context of this discussion is simply that there do exist a variety of situations in which reasonable sets of assumptions lead to the conclusion that the use of cleaned coals is the least-cost option for meeting SO_2 emission limits. This conclusion holds especially for cases where the emission limit is 1.2 pounds per million Btu or greater, and it includes some cases where PCC is used in conjunction with flue gas desulfurization.

Table 2

Costs of Alternative Strategies for Meeting Emission Limits of 1.2 lb/10^6 Btu SO_2, 0.1 lb/10^6 Btu Particulates (Central Ohio Location)

Coal Source, Type	Delivered Coal Cost (¢/10^6 Btu)	Cost of ESP (¢/10^6 Btu)	Cost of FGD (¢/10^6 Btu)	Total Cost (¢/10^6 Btu)
West Virginia, cleaned	149	15.6	-	165
Wyoming, uncleaned	156	25.5	-	181
Ohio, uncleaned	111	13.0	65.0	189

With these encouraging results in mind, let's look at the barriers that are impeding their realization. Given the constraints on the length of this paper, we will highlight only the key points of the Teknekron analysis.

Investment Barriers and Strategies for Overcoming Them

Teknekron began with the recognition that PCC alone or in combination with other strategies had previously been judged by several engineering studies--including some of our own--to be the least expensive way for electric utilities and other coal-burning industries to comply with the SO_2 emission standards, especially standards of around 1.2 pounds per million Btu or greater. But we also recognized another critical point--namely, that least-cost solutions from the customary engineering perspective do not always prove feasible or even least cost when certain nonquantifiable or hard-to-quantify factors are taken into account.

Accordingly, we embarked on first-hand interviews with a variety of potential PCC investors to identify the factors inhibiting the use of PCC for SO_2 emission control. We spoke with bankers in New York, Chicago, and Pittsburgh who have been intimately involved in the financing of cleaning plants. We also spoke with representatives from a variety of coal companies, utilities, and industries that are now planning to burn coal.

Before examining our analysis of these interviews, let's look at the investment environment in general.

All investment decisions, whether related to PCC or not, are made under uncertainty. Moreover, each investment decision is part of a web of other decisions--part of a portfolio that covers many different types of investment, each with particular risk factor and an appropriate return.

Even if investments were not made in this interdependent manner, each would require some combination of assurances. The investor would want some assurance of a market. He would want some assurance of rapid payback or of a high discount rate applied to anticipated cash flows. He would want a relatively high rate of return on his investment. And he would want reasonable options to pursue in case the market for his service or product disappeared.

With all these assurances there would still be risk; and even with investments of relatively little risk, there might be institutional or legal constraints. Circumventing such constraints could be costly--for example, it would be costly to rely on internal funds when borrowed funds would be cheaper. Generally, such decisions are not made without extremely compelling reasons--for example, to stay in business.

The investment environment in general, then, is complicated and filled with uncertainty. For the potential coal-cleaning investor, as we shall find, the complexity and uncertainty are magnified. Getting from here to there--turning a contemplated coal-cleaning investment into a real one--means overcoming a range of barriers: barriers of data deficiency, institutional barriers, and economic and regulatory barriers.

Barriers of Data Deficiency

To begin with, the potential applications, or markets, for coal cleaning are not well understood. The key factor here is uncertainty regarding future SO_2 emission standards. On the one hand, there is movement toward greater stringency, through a tightening of New Source Performance Standards and State Implementation Plans. On the other hand, the current standards are often not being enforced (at least one-third of all coal burned in utility boilers is technically in noncompliance), and in some cases SIPs are being relaxed (which of course tends to increase the proportion of coals in compliance).

In a very real sense, the issue for the potential PCC investor is not what the standards are but what they will be. Here are the questions the investor is asking now:

- What specific standards will be set, will be enforced, for what period of time, in what state or region, for what particular site, and for which plant categories?
- And, assuming reasonably reliable answers to these questions, what design and investment alternative for meeting future SO_2 limitations will prove to be the least-cost or otherwise "best" option?

The answers, which are very difficult to come by, are particularly vital for coal consumers. And they are of great concern also to coal companies, equipment manufacturers, and regulatory authorities--in other words, to the commercial parties who need the answers for marketing and contract negotiations, and to the public authorities who need them in order to respond with appropriate regulatory, legislative, and R & D policies.

As matters now stand, the vast number of circumstances and control options to consider can be overwhelming. Without the benefit of some very sophisticated modeling--such as the Utility Simulation and Coal Assignment models, which we have developed over three years at a sizable investment of EPA research funds--the current or would-be coal consumer may be so defeated by the plethora of possibilities that he will fall back on those options that seem most familiar or most risk-free. Among the most familiar options, for example, would be the purchase of low-sulfur western coal. Among the most risk-free, though this is certainly a debatable point, might be the use of scrubbers. But these options might not be the least costly ones in the long run to the ultimate consumer--that is, to the buyer of electricity.

Thus, while PCC either alone or combined with blending or scrubbing may well be the "best" strategy, it may be ignored.

But what if the potential investor doesn't ignore PCC? At the heart of his problem then is the matter of matching potential markets with appropriate PCC technologies. Consider the potential markets. There are five:

- Utility boilers subject to SIP limits
- Utility boilers subject to the current NSPS
- Utility boilers subject to future NSPS
- Industrial boilers subject to SIP limits
- Industrial boilers subject to forthcoming NSPS

Only one of the five is well-defined at present: the second market, utility boilers subject to the current NSPS of 1.2 pounds of SO_2 per million Btu. Since the NSPS for industrial boilers and the NSPS revisions for utility boilers will soon be forthcoming, educated guesses can be made about the nature of these potential markets.

Boilers subject to SIPs are something else again. SIPs, theoretically tied to ambient air quality standards, are bound--even designed--to change. What an SIP for a particular plant might be two or three years from now (the time it takes to build a PCC facility) is highly problematic. It could be strongly affected by such developments as the use of a greater number of ambient air monitoring sites or the use of more sophisticated diffusion modeling techniques.

Furthermore, SIP standards vary from state to state, and from region to region within a state. In addition, some states set standards on a unit-by-unit or stack-specific basis. All this variation frustrates the planner attempting to generalize with regard to PCC's role in the SIP-affected market. Of course, a given coal burner knows well what the current standards for his boilers are --but future standards (the ones of interest to the potential PCC investor) are another matter.

There is still another factor that cannot be ignored: with so many boilers now being fired in noncompliance, the potential PCC investor wonders whether noncompliance will continue to be a viable strategy. And what if SIP standards are in fact enforced? By what means will they be enforced? By lengthening the averaging period or otherwise making the standards less stringent?

Recall now that we targeted as the heart of the problem the matching of markets with appropriate PCC technologies. We have just looked at the markets, which turn out to be a most uncertain matter. Now, looking at technology, we find that there are three complicating factors.

First, potential investments are thwarted by the image PCC has as an ash reducing, not a sulfur reducing, process.

Second, for those potential investors who do connect PCC with sulfur removal, there is great concern about the reliability and site-specific applicability of engineering studies that project processing costs. The investor motivated by a preliminary study to undertake a rigorous investment analysis will find scores of PCC configurations and scores of cleaning levels from which to choose. Chances are that he will not be comfortable with the numerous options and range of costs presented him. Unless we begin very soon to develop a systematic and simplified method for presenting the investor with realistic options, it is likely that complexity alone will defeat the widespread adoption of PCC.

The third factor complicating the technical side of the market-technology equation is the startling array of non-PCC and with-PCC combinations. These combinations, listed below, range from FGD with different types of coals to the firing of high-sulfur coal with no control technology.

- Use of low sulfur compliance coal.
- Blending of low sulfur and higher sulfur coals.
- FGD with high, medium, or low sulfur coals.
- FGD + PCC with high or medium sulfur coals.
- PCC + blending.
- Chemical coal cleaning with or without FGD and/or blending.
- Use of medium or high sulfur coals without sulfur controls.

The first six options imply stringent emission limitations. The last option implies relatively lax limitations, or the seeking of variances, or the violation of standards. The first six could apply to any new or existing source; and the last option, presumably, only to existing sources.

Now, let's go back for a moment to the first complicating factor--the point about PCC's image as an ash reducing, not a sulfur reducing, process. Most of the potential investors we spoke with were surprised that PCC could be considered seriously as a sulfur removal strategy for most boilers subject to NSPS revisions. Some were aware that the EPA Administrator has authority under the Clean Air Act revisions to permit credit toward the percentage removal requirement for precombustion cleaning, but they were skeptical that PCC combined with FGD could prove to be the least-cost compliance option.

The benefits of PCC that our interviewees did generally know about are listed in the first column of table 3. Other potential benefits, shown in the second column, were hardly appreciated at all. Thus, of all benefits identified by Teknekron, most potential investors are aware of only about one half.

Even knowing of these benefits, the investor considering the market for boilers subject to mandatory use of FGD, as in the case of the revised NSPS, might understandably ignore the PCC technologies if their payoffs were not proved to be dramatically great. Further, the same investor might find it easier to focus on one technology, FGD, with one particular type of coal, than to consider a range of technologies applied to a range of coals.

Can we give that investor any rules of thumb to use in weighing the benefits of combining PCC with FGD to comply with the NSPS? Certainly Hoffman-Munter may have made a contribution by estimating that the PCC/FGD combination makes sense if less than 50 percent of the flue gas need be scrubbed to achieve compliance. But rules of thumb don't really work for real-world, site-specific situations. At most, they may motivate the would-be investor to undertake further investigation by at least pointing him in the general direction of a least-cost solution.

Now, what about the potential investor considering PCC with or without FGD to meet the current NSPS and SIPs? Here there seems to be a somewhat better appreciation of PCC's beneficial role. But even here the spate of options involving different process combinations and coal types tends to complicate the issue and cloud the financial analyst's understanding. Obviously, too few benefits of PCC are known to too few people. There's been no great rush to invest in PCC for sulfur removal pruposes. Greater dissemination of information would certainly seem to be in order.

Table 3

Benefits of PCC

Known Benefits	Other Benefits
Reduced transportation costs	Reduced sulfur variability
Reduced ash disposal costs	Reduced boiler maintenance
Reduced FGD investment	Reduced ESP costs
Reduced FGD operating costs	Expanded coal supply options
Reduced pulverizing costs	May eliminate need for reheat after FGD
	Increased FGD reliability

An uncertain grasp of benefits, an uncertain future for SO_2 regulations, an uncertain market, and an uncertain combination of technologies--all these add up to a serious problem of data deficiency for the potential investor in PCC.

There are some obvious strategies for reducing the uncertainty: EPA can continue to disseminate information on the benefits of PCC through periodic conferences such as this one or through "technology transfer" seminars. Other strategies should also be pursued. One, briefly mentioned above, is to develop a systematic and simplified method of analyzing PCC technologies and applications. The other is to expand the program carrying out commercial-scale PCC demonstrations.

These initiatives should go far toward breaking down the barriers of data deficiency. They will not, however, address a second set of factors we have uncovered. These we group under the heading of "institutional barriers."

Institutional Barriers

Institutional barriers are best discussed in terms of particular types of would-be investors. Let's look first at coal companies. Teknekron found no significant institutional barriers in the case of large coal companies but uncovered real problems for the small firms.

Currently, about 15 percent of the nation's coal is produced in about 80 percent of our mines. Generally, the coal produced at these mines (about 4,000 in number) is sold without any preparation and shipped at single-car rates, which means this coal costs $2 to $3 more per ton to ship than coal produced in the same area but from large mines.

The difficulty for the small coal company hinges on capital expenditure. If any coal company, large or small, is to take advantage of unit-train rates, it must be able to guarantee high-volume movement between a single source and a single market, and it must have a means for loading the unit-trains quickly and efficiently. That means getting a coal transloader, and that involves a major capital expenditure. Small coal producers cannot afford that kind of investment. Nor can they afford to build preparation plants.

But it is precisely these small companies that may control a significant fraction of the nation's cleanable reserves--especially in Central Appalachia. How, then, can the small company's resources be tapped for PCC? Teknekron has considered several possible strategies and has concluded that the most promising would be for small coal companies to form cooperatives. Through these cooperatives, several small companies together could finance the kind of capital investment needed for a PCC plant. There is certainly precedent for this: co-ops have been successfully organized and operated in several fields of commerce, most notably in agriculture.

Consider now the barriers faced by electric utilities. Before a utility can approve a PCC investment, it must be reasonably certain about the answers to a number of questions. For example:

- How speculative is the PCC investment?
- How does PCC fit into the company's compliance strategies?
- Will PCC accommodate future needs?
- Are boiler modifications necessary?
- Is it better to contract for cleaned coal than to clean at the power plant?

- Should there be a joint venture with a coal company?
- Should there be a multistream operation for several power plants or with industrial coal consumers?
- Should the PCC plant be funded through an unregulated subsidiary?
- Should PCC be developed with captive mines?
- Will the PUC approve cost passthrough?
- Will the PUC approve inclusion of PCC in the rate base?

We cannot discuss all the questions in this brief paper but would like to devote a few pages at least to potential problems associated with captive mines and actions by the regulating public utility commission. PUCs, like utilities, are under constant and conflicting pressures to ensure that electricity will be supplied on a reliable basis at lowest reasonable cost. Maintaining an acceptable balance between ensuring reliability, on the one hand, and least cost, on the other, can prove very difficult. This is especially so since reliability and cost determinations must be made on a prospective basis, requiring the use of forecasting techniques.

More stringent environmental regulations tend to have adverse effects on both anticipated reliability and anticipated costs. In this regard, options for controlling SO_2 emissions from existing and new coal-fired plants simply add another set of factors for PUCs to take into account.

One of the ways utilities have been responding to concerns about cost and about reliability of both coal and electricity supply is to rely more heavily on long-term contracts. At the same time, growing numbers of utilities are entering the coal-mining business to produce coal for their own needs (and sometimes for other utilities). In 1976, captive coal represented about 11 percent of all coal delivered to electric utilities. By 1985, it is expected, this figure will have risen to about 19 percent. Utilities now control about 10 percent of the nation's recoverable coal reserves, two-thirds of which are in the western states.

Although utilities entering the coal business are generally large--for example, Texas Utilities, TVA, AEP, Pennsylvania P & L, and Duke Power--smaller utilities are considering cooperative ventures to meet their own needs. The Western Coal Association is the first example of a co-op being formed (by ten utilities) for both fuel procurement (contracts negotiated with independent producers) and production purposes.

The significance of these developments for PCC is that utilities could be in a position to invest in their own cleaning facilities at the mine--be it mine-mouth generation or not. Moreover, with the apparent willingness of at least some PUCs to permit such vertical integration, utilities may gain valuable bargaining strength in negotiating with independent coal companies for coal, including cleaned coal.

However, it should be noted that not all PUCs view the benefits (quantifiable and nonquantifiable) of vertical integration as greater in all cases than the costs. This does not mean that such PUCs would necessarily disapprove of vertical integration; instead, it might mean that they would make the possible financial advantages to the utility in the arrangement less apparent.

Three advantages to utilities in captive operations are:

- Greater reliability of supply
- Potential for lower costs of fuel
- Leverage in negotiating contracts with independent coal companies

Other possible benefits include tax advantages and, in the case of unregulated subsidiaries, the potential for greater return on equity than may be likely for regulated aspects of the business. The potential for greater return, however, will not always be realized. There are business risks to consider, although with an assured market these risks are presumably reduced. PUCs may see such risks reduced to the extent that the return to the captive supplier is not "allowed" to be greater than the return to the parent. (In fact, a PUC cannot really control the return on equity; this is determined in the business and financial marketplace.) The PUC's choice of transfer prices between supplier and purchaser may prove to be a disincentive to vertical integration and hence an institutional barrier to PCC investment.

There are also definite disadvantages to utilities moving into captive operations. Probably the most significant of these is that utility management is relatively inexperienced in dealing with mining companies and miners. Electric utilities are capital intensive, not labor intensive. A different set of skills may be required for captive operations. Further, management resources might be better applied at the very complex generation, transmission, and distribution end, rather than spread across another area.

The issue of management skills is important, too, when considering PCC operations. Since coal companies have traditionally managed the efforts of preparation engineers, they have an advantage in considering a PCC investment for sulfur removal purposes. Power engineers definitely speak a different language from that of preparation and mining engineers.

Both PUCs and the utilities will be weighing these advantages and disadvantages of the move to captive coal and of coal washing for sulfur removal. Whether PUCs will prove an institutional barrier to PCC investment is still uncertain. Presumably, if PCC in captive operations could be demonstrated clearly to be the least-cost way to produce environmentally acceptable coal, PUCs would approve the plan.

The final set of institutional barriers are those faced by industrial coal consumers. Here, the most important point to understand is that no industry will adopt PCC for sulfur removal unless it is first convinced that the use of coal itself is economically wise.

We know that many firms are now considering the use of coal. Among them are firms located near a mine or capable of being so located, firms that expect to have a need for relatively large amounts of coal, and firms that have space available for coal storage, rail facilities, and PCC waste disposal.

Another important point to keep in mind is that the new source standards applicable to industrial boilers will probably be less significant than those for utility boilers. Obviously, we do not yet know what standard these non-utility boilers will have to meet; and, any event, recognizing that PSD and nonattainment policies must be reckoned with, we can expect that the issue will be resolved on site-specific, boiler-specific, and perhaps firm-specific bases. Despite these complications, we believe it reasonable to assume that the great majority of industrial boilers built in the near future will be subject to emission limitations that can be met by means other than flue gas scrubbing.

This is where coal cleaning enters the scene. In many parts of the country, new industrial boilers will be able to meet the applicable SO_2 emission limitations through the use of cleaned coals. This will happen where the levelized cost of using cleaned coals is perceived to be lower than the cost of using naturally occurring low-sulfur coals or blending low-sulfur with medium-sulfur coals.

But, again, cleaned coals won't have a role to play in this market unless industry uses coal. And industry, in many cases, won't use coal unless it does one of two things:

- Forms consortia to acquire reserves, finance prep plants and transloaders, obtain unit-train or trainload loads, and acquire land and facilities for coal storage and handling
- Enters into joint ventures with coal producers to finance the construction of such capital items as PCC plants

There are problems involved in establishing and maintaining these institutional arrangements. One of the basic problems is that, compared with public utilities, nonutility firms face a higher degree of business risk. This is manifest in utility versus nonutility "long term" fuel-supply contracts. The industrial firm may see a "long-term" contract as spanning three to five years, whereas utilities generally take it to mean ten to thirty years. Their monopoly status affords utilities the luxury of such contracts. Nonutility firms, by necessity, have shorter planning horizons--at least insofar as fuel purchases are concerned.

Because their fuel-supply contracts are shorter, or at least have been so traditionally, nonutility firms must see to it that the sizable capital investments made in coal-cleaning plants are protected by extraordinary financial assurances. This is true whether such investments are made by coal companies or by the industrial coal consumers themselves.

To provide such assurances, a consortium must be able to demonstrate with reasonable certainty that it will honor its commitments to the coal company and absorb any losses or higher costs that may come about should one member of the consortium be unable to continue to receive cleaned coal. Such assurances are perhaps more easily provided through joint ventures between coal consumers and producers. But there may be a significant problem in matching the asset backing and reliability of the parties to the venture.

Another possible arrangement for nonutility firms to consider is a joint venture with a utility--perhaps in a multistream coal-cleaning facility located at the plant or at the mine. Significant savings could result in financing, in economies of scale in cleaning plants, and in transport. If the cleaning facility were located at the plant, a particularly good arrangement would work where cogeneration projects are contemplated.

However, joint ventures pose many potential institutional problems that would need to be resolved. For example, nonutility firms would be particularly concerned lest joint ventures involving the regulated portions of electric utilities lead regulatory agencies to believe they have authority to scrutinize the accounts of the unregulated firms. Furthermore, if PUCs were to take interest in the contractual arrangements established between utilities and industrial firms, they could require as protection for utility investment that these contracts be of the long-term variety that might make nonutility firms uncomfortable.

We proceed now to the final barrier uncovered by Teknekron. This barrier involves two constraints which can be seen as either economic or regulatory.

Economic/Regulatory Barrier

As indicated earlier, it is only recently that the focus on coal cleaning has broadened to include sulfur as well as ash removal. Since emission standards in many cases are moving toward greater stringency, utilities and some other coal-burning firms are paying more and more attention to coal cleaning as an alternative to the expensive compliance options of buying low-sulfur western coal or installing scrubbers.

But a major factor that may inhibit the adoption of coal cleaning as a sulfur removal strategy is that, unlike flue gas desulfurization, cleaning plant investments do not now qualify for investment tax credits or as pollution control investments. These determinations, made by the IRS, have put coal cleaning on an unequal footing with scrubbers as well as with naturally occurring low-sulfur coals (which of course do not require capital investment of the kind discussed here).

The effect of a PCC plant's failure to qualify for the investment tax credit is obvious: higher taxes payable to both states and the federal government. The ruling in this regard, having to do with whether the plant is in fact a single entity or simply an assemblage of parts, could certainly be reviewed in depth with an eye toward urging the IRS to reconsider its posture.

The effect of PCC's failure to qualify as a pollution control investment is somewhat more complex. The ruling on this matter is based on the IRS's belief that PCC investments are made principally for purposes of gaining a commercial advantage over firms that do not clean the coal they sell. The fact that substances which may pollute are removed in the cleaning process is seen as incidental to the principal purpose of the investment.

Section III (a)(1) of the 1977 amendments to the Clean Air Act may provide the rationale for suggesting that the IRS reconsider this ruling. This section authorizes the EPA Administrator to permit "credit" toward the percentage removal requirement in NSPS revisions for precombustion cleaning of coal. Since the only other way to receive "credit" is by using flue gas desulfurization, and since FGD now qualifies as a pollution control investment, this would appear to offer _prima facie_ evidence that precombustion cleaning is placed on unequal footing with postcombustion cleaning as a pollution control option.

If PCC were granted status as a pollution control investment, PCC investors might reap as many as four financial and economic benefits:

- _Accelerated depreciation_ (over five years) could be taken for tax purposes. At present, a PCC plant is depreciable over its anticipated useful life.
- _A five percent investment tax credit_ might be made available, although a parallel ruling on the separate but related issue of investment tax credit qualification would be required.
- _Tax-exempt pollution control bonds_ might be made available to finance the facility. The economic benefit of such financing would vary from firm to firm.
- PCC operations in some states might be granted _exemption from state sales and use taxes_.

We believe that steps should be taken to urge the IRS to reconsider its rulings. It is not possible at this time to estimate with any certainty what the combined effect of these initiatives would be on per-ton cleaning charges. These matters are quite firm-specific, plant-specific, and state-specific. However, we believe the initiatives would strongly enhance the market prospects for coal cleaning as an SO_2 removal process.

ECONOMICS OF COAL CLEANING AND FLUE GAS DESULFURIZATION FOR COMPLIANCE WITH REVISED NSPS FOR UTILITY BOILERS

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ABSTRACT

Coal quality is declining and the effects of ash composition, ash, and sulfur have increased the frequency of unscheduled outages and deratings and increased operating and maintenance costs. Removing the mineral matter and pyritic sulfur from the coal prior to combustion will improve power plant performance and reduce sulfur dioxide emissions as shown in this paper.

In this study coal cleaning, combined with flue gas desulfurization, was more cost effective when compared with flue gas desulfurization alone. Although the capital investment and preparation costs are higher, the credits gained by providing a superior product offset these costs. Removal of mineral matter and pyritic sulfur by coal cleaning reduces the investment cost for flue gas desulfurization systems. These savings exceed the investment cost for coal cleaning.

Case 1 assumes run-of-mine coal is fired in two 1000-MW units followed by flue gas desulfurization. Case 2 assumes 50 percent of the mineral matter and 60 percent of the pyritic sulfur is removed before combustion, followed by flue gas desulfurization.

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Joseph W. Leonard and David R. Mitchell, Coal Preparation, The American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., New York, 1968.

DISCLAIMER

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I. Introduction

The 1977 Clean Air Act Amendments specify that new stationary coal-fired sources regulated by EPA must use the best available control technology, use a method of continuous pollution control, and achieve a percentage reduction of the regulated pollutants. Any reduction of a pollutant by post extraction fuel processing may be credited to the percentage reduction requirement.

EPA is currently preparing to propose revised New Source Performance Standards (NSPS) for fossil-fueled boilers for power generation. The regulations under consideration require a minimum 85 percent reduction (24-hour average) in sulfur between the point of coal extraction and the point of discharge of combustion products to the atmosphere and limit sulfur emissions to no more than 1.2 lb $SO_2/10^6$ Btu (24-hour average). A separate provision of the standards will permit a 75 percent minimum reduction in sulfur and an exemption of the 1.2 lb $SO_2/10^6$ Btu emission limit three days per month. This provision is to allow for variations in fuel sulfur levels and pollution control equipment performance. While promulgation of these regulations would effectively preclude the use of coal cleaning as a sole method for complying with SO_2 standards in new electric utility boilers, coal cleaning with scrubbing may be used in some cases in a cost-effective manner to meet the revised NSPS.

In the following exercise some of the important factors that can affect the cost of producing electricity from coal while meeting air quality standards are illustrated.

Cases 1, 3, and 5 assume uncleaned coal is fired in the two 1,000-MW units followed by flue gas desulfurization. Cases 2, 4, and 6 assume 50 percent of the mineral matter and 60 percent of the pyritic sulfur are removed before combustion followed by flue gas desulfurization. In all of the coals the study assumes no changes in the basic power plant design, even though the electrical output and other parameters (such as coal consumption) may change slightly. Coal cleaning and FGD costs were estimated from the necessary requirements to fulfill the needs of the basic power plant design common to all cases.

The basic power plant design consists of two 1,000-MW pulverized coal units designed with a heat rate of 9,000 Btu/kWh and a capacity factor of 65 percent. The operating life of the plant is 30 years. The yearly design generation is 11 billion kilowatthours, utilizing 5 million tons of coal a year. The assumed raw coal analyses are:

	Case 1 & 2 W. Ky. 11	Case 3 & 4 W. Ky. 9	Case 5 & 6 W. Ky. 12
Moisture, %	6.7	6.55	5.75
Ash, %	20.55	14.85	26.05
Total Sulfur, %	4.5	4.5	4.7
Pyrite, %	2.39	2.35	3.08
Sulfate, %	0.43	0.43	0.21
Organic, %	1.64	1.72	1.40
Heating Value (as rec'd)	10,416	11,363	9,538
Cost, $/ton	22	20	15

In all cases 85 percent removal of sulfur is required between the mine and the stack discharge. All the sulfur input to the furnace totally evolves as sulfur dioxide. In all cases assume the ash overhead to be 80 percent requiring 99.5 percent fly ash removal within the scrubber.

Penalty

Coal properties that have the most effect on boiler operation are ash composition, ash content, and sulfur content. Ash composition affects and influences the slagging of furnace walls and fouling of convection passes. Fouling decreases heat transfer and promotes wastage by external erosion in the convection passes, the induced-draft fans, and plugs the air preheaters. Excessive ash content overloads the electrostatic precipitators and bottom ash handling equipment. Sulfur content influences the operation and maintenance of feeders, pulverizers, furnaces, soot blowers, air preheaters, dust collectors, and induced-draft fans. Pyrites cause excessive wear of the pulverizer internals. Ash and sulfur contents directly affect the heating value of the coal and along with moisture, limit the capacity of the combustion system.

Coal quality has declined in recent years and has contributed to an increase in unscheduled outages, unit deratings, and operating and maintenance costs.

Figure 1 shows the general trend of the relationship between coal quality and coal quality related costs. The trend is essentially linear below a point where the boiler is designed to handle coal of a certain quality. As coal quality declines further, the costs rise exponentially and, at some point the unit cannot be operated without an excessive forced outage rate or an unacceptable loss in generating capacity. The

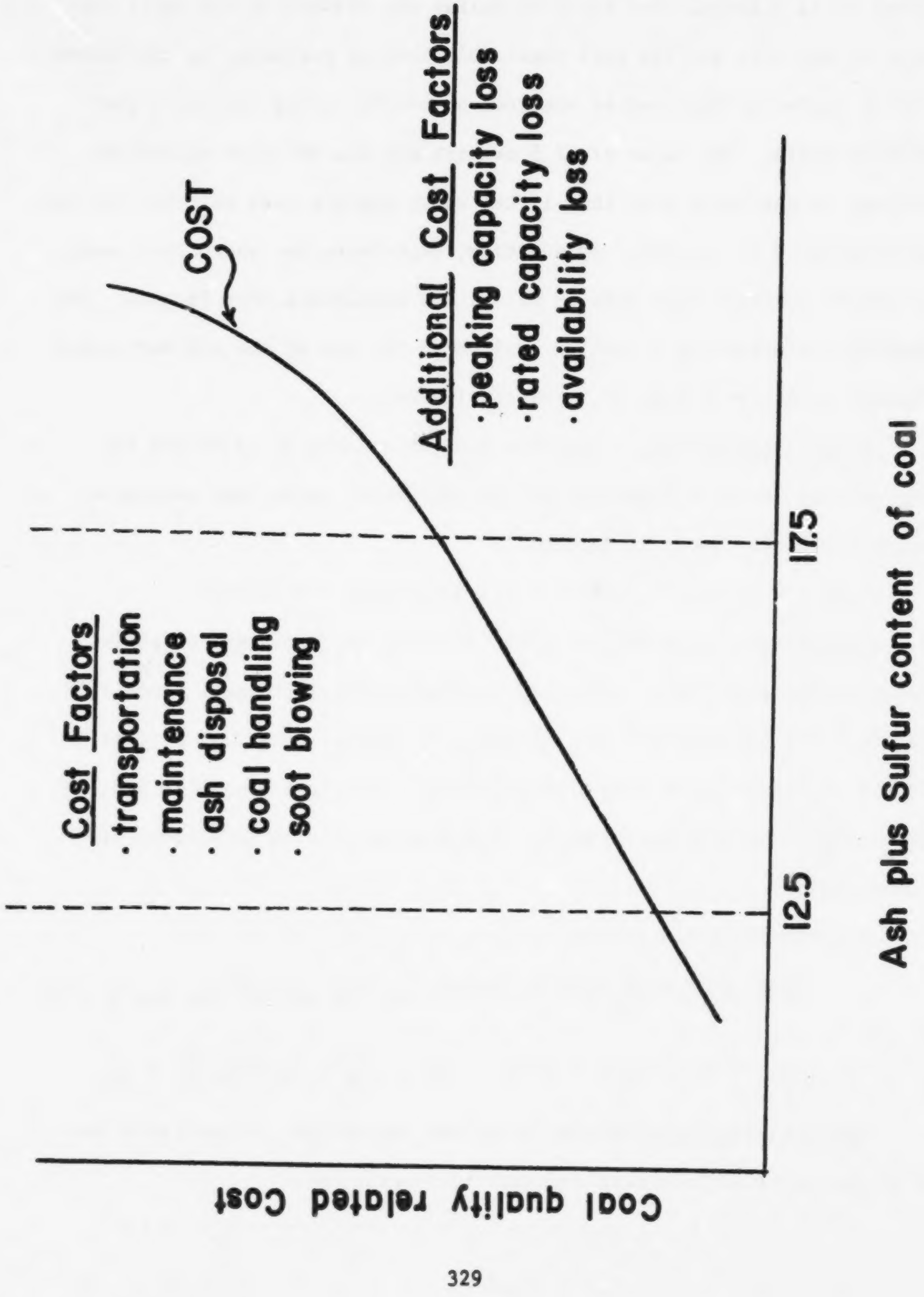

Coal quality related Cost
Ash plus Sulfur content of coal
12.5
17.5
COST
Cost Factors
· transportation
· maintenance
· ash disposal
· coal handling
· soot blowing
Additional Cost Factors
·peaking capacity loss
·rated capacity loss
·availability loss

FIGURE 1

value of 12.5 percent for ash plus sulfur was assumed on the basis that this is the best quality coal obtainable through purchases in the Tennessee Valley region or that can be obtained by beneficiating available poor quality coals. The value of 17.5 percent for the ash plus sulfur was assumed on the basis that this is the worst quality coal that the boilers were designed to utilize. In addition, experience has shown that coals of poorer quality cause some or all of the additional cost factors. The penalty for operating a unit on coal where the sum of the ash and sulfur content totals more than 12.5 percent includes:

Transportation Costs--Assume a freight penalty of \$2.50 per ton per percent above 12.5 percent and an additional charge for excessive moisture content above 10 percent.

$$\text{Cost} = 2.50\ (\text{ash} + \text{sulfur} - 12.5 + \text{moisture} - 10)(0.01)$$

Maintenance Costs--Assume labor costs to be 50 percent of power plant maintenance costs. The coal contract price adjustment since 1953 has been 0.1 cent per 10^6 Btu for ash plus sulfur above 12.5 percent. Trades and labor rates have increased since 1953 from \$5,112 to \$15,100 per year, or by a factor of 2.95. Overtime amounts to 15 percent of labor costs.

Maintenance Cost Factor =

$$\frac{(0.1)\ 2.95 + (0.1)\ 2.95\ (1.15)}{.50} = \$0.635 \text{ per } 10^6 \text{ Btu per \% A + S}$$

$$\text{Cost} = 0.635\ (\text{ash} + \text{sulfur} - 12.5)\ (\frac{\text{Btu}}{\text{lb}})\ (2{,}000\ \frac{\text{lb}}{\text{ton}}) = \frac{\$}{\text{ton}}$$

Ash Disposal Costs--Assume \$2.22 per ton of ash. A coal with ash plus sulfur of 12.5 percent contains 10 percent ash.

$$\text{Cost} = \left[\frac{(\text{20 lb ash/ton coal})}{\text{1\% ash over 10\%}}\right] \left(\frac{\$2.22}{\text{ton ash}}\right) \left(\frac{\text{1 ton ash}}{\text{2000 lb ash}}\right) =$$

$$\frac{\$0.0222}{\text{1\% ash over 10\% per ton coal}}$$

$$\text{Cost} = (\text{ash} - 10)\ 0.0222 = \frac{\$}{\text{ton coal}}$$

The following additional costs are incurred for ash plus sulfur content greater than 17.5 percent (exponential portion of curve in Figure 1).

Peaking Capacity Loss--Assume wide open valve peaking capacity is required 2 percent of the time or 172.5 hours per year. The unit capacity factor is 45 percent. Peaking capacity is replaced with gas turbines at an incremental cost of 32 mils per kilowatthour. Peaking capacity is 10 percent of rated capacity. One-third peaking capacity is lost for each percentage point that the ash plus sulfur content exceeds 17.5 percent.

$$\text{\% Peaking loss} = \frac{(\text{ash + sulfur}) - 17.5}{20.5 - 17.5} \times 100 = \%$$

Cost =

$$\frac{(\text{Rated capacity})\ (0.10)\ (\text{\% Peaking loss})\ \left(\frac{\text{Hours}}{\text{Year}}\right)\ (\text{Incremental cost})\ (\text{Heating value})}{(\text{Heat rate})\ (\text{Gross Generation})}$$

Rated Capacity Loss--Assume rated capacity is lost at the rate of 3 percent for each percentage point that ash plus sulfur exceeds 17.5 percent. Rated capacity loss is replaced 50 percent of the time at an incremental cost of 10 mils per kilowatthour. The unit capacity factor is 56 percent.

$$\text{Rated capacity loss} = (\text{ash + sulfur} - 17.5)\ (0.03)\ (\text{rated capacity})$$

$$\text{Generation loss} = \left(8760\ \frac{\text{HR}}{\text{YR}}\right)\ (\text{capacity factor})\ (\text{rated capacity loss})$$

$$\text{Cost} = \frac{(\text{generation loss})\ (\text{incremental cost})\ (.5)}{\left(\frac{\text{tons}}{\text{year}}\right)}$$

Availability Loss--Assume 1 percent loss in availability for each percentage point that ash plus sulfur exceeds 17.5 percent. The unit capacity factor of 56 percent corresponds to an availability of 72 percent.

Availability loss = (ash + sulfur) - 17.5

Cost =

$$\frac{(\text{lost generation})\ (\text{incremental cost})\ (.5)\ (\text{heating value})\ (2000\ \frac{\#}{\text{ton}})}{(\text{normal generation} - \text{lost generation})\ (\text{heat rate})}$$

The penalties are summarized as follows.

	Case 1 (WK11)	Case 3 (WK9)	Case 5 (WK12)
Transportation	0.26	0.085	0.35
Maintenance	1.66	0.989	2.21
Ash Disposal	0.23	0.108	0.36
Peaking Capacity Loss	0.29	0.196	0.27
Rated Capacity Loss	3.15	0.48	5.86
Availability Loss	1.22	0.30	2.17
$\frac{\$}{\text{ton}}$	6.81	2.258	11.22

Flue Gas Desulfurization

Flue gas desulfurization (FGD) is required to meet the New Source Performance Standard. Cases 1, 3, and 5 assume FGD is used alone to meet NSPS. Cases 2, 4, and 6 assume coal cleaning followed by FGD. A Turbulent Contact Absorber (TCA) was selected for the FGD system, with limestone as the absorbent. The design premise for the FGD is shown in Table I. The FGD capital investment and the annual revenue requirements are shown in Figures 2 through 7.

Table I

TCA SCRUBBER SYSTEM FOR 1,000-MW UNIT

Scrubber Description

Number of Operating Scrubbing Trains	8
Number of Redundant Scrubbing Trains	1
Number Beds Per Train	3
Height of Spheres Per Bed (inches)	5
Liquid to Gas Ratio (gal/1,000 ACF)	55
Scrubber Gas Velocity (ft/sec)	12.5
TCA Pressure Drop Across Three Beds (in. H_2O)	8.6
Total System Pressure Drop (in. H_2O)	14.8
Stoichiometry Ratio $\left(\frac{\text{Mole CaCo}_3}{\text{Mole SO}_2\text{ Absorbed}}\right)$	1.5
Entrainment Level (wt. %)	0.10
EHT Residence Time (min)	12
SO_2 Oxidized in System %	30
Solids in Recirculated Slurry (wt. %)	15
Scrubber Inlet pH	5.89

Steam Reheater (In-line)

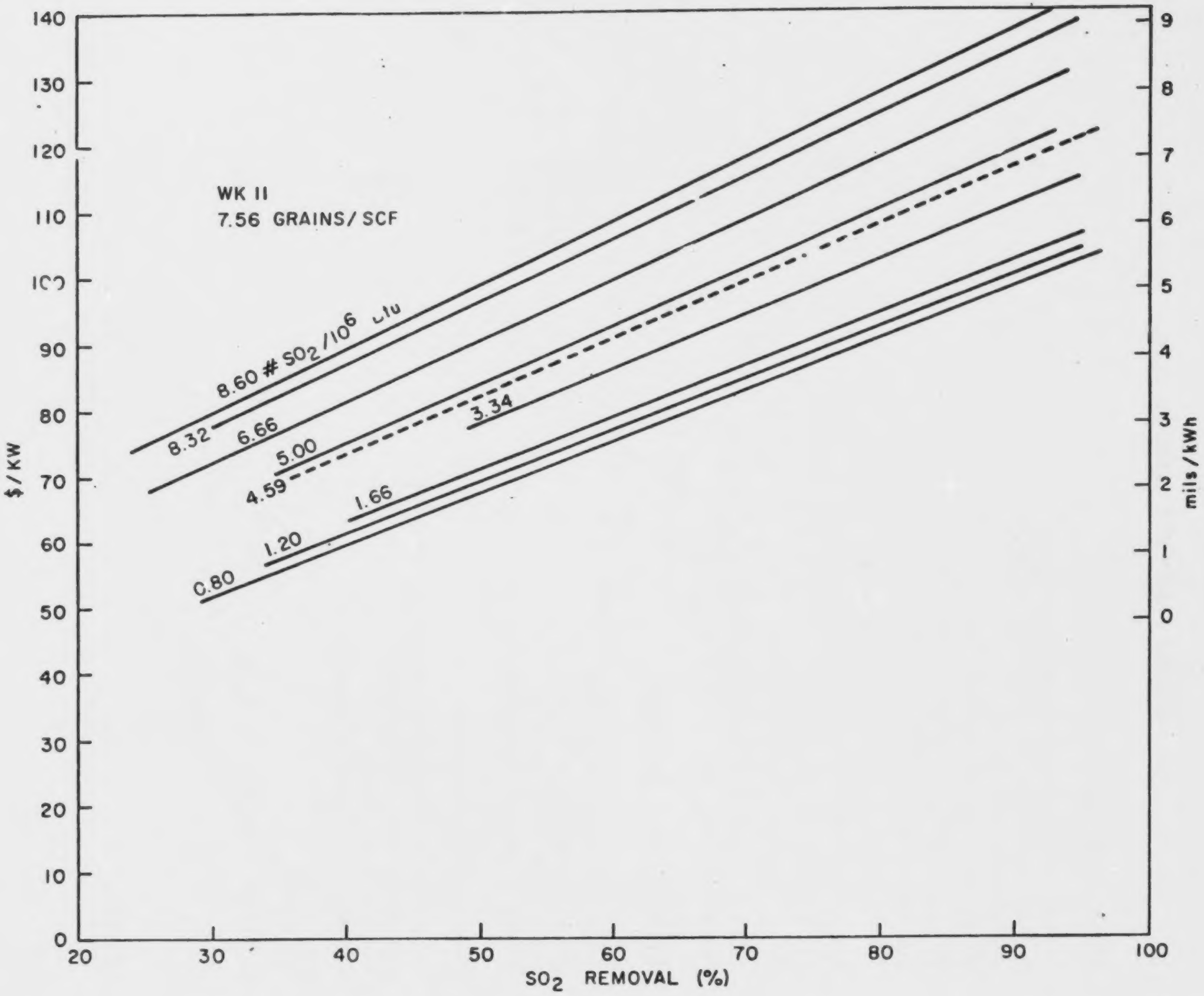
Superficial Gas Velocity (ft/sec)	25
Saturated Steam Temp (°F)	470
Steam Consumption (lb/hr)	217,700
Inlet Flue Gas Temp (°F)	126
Outlet Flue Gas Temp (°F)	175

Solids Disposal System

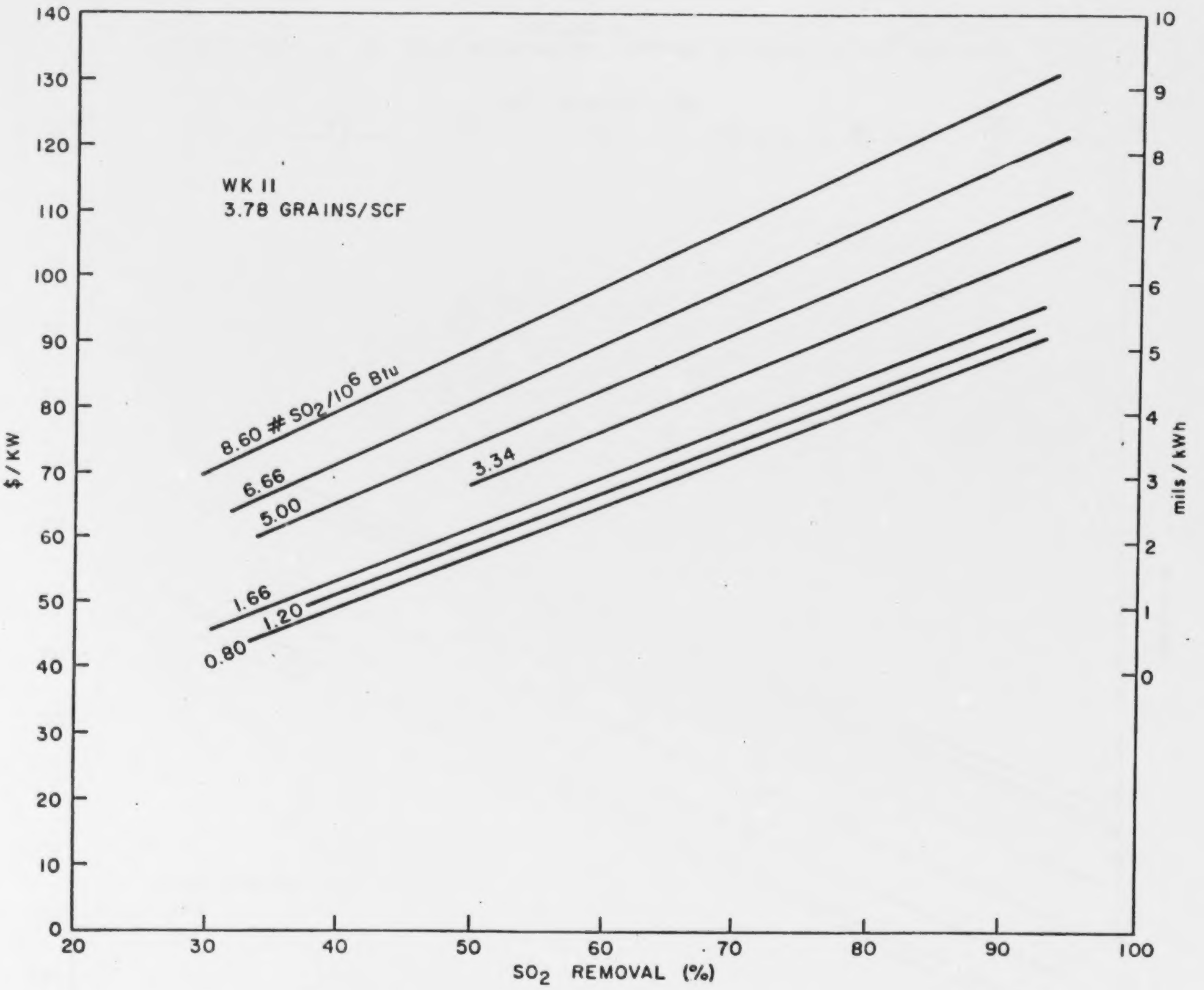
Solids in System Sludge Discharge (% wt.)	40
Available Pond Area (Acres)	9,999
Maximum Pond Depth	25
Distance to Pond (mile)	1

Absorbent

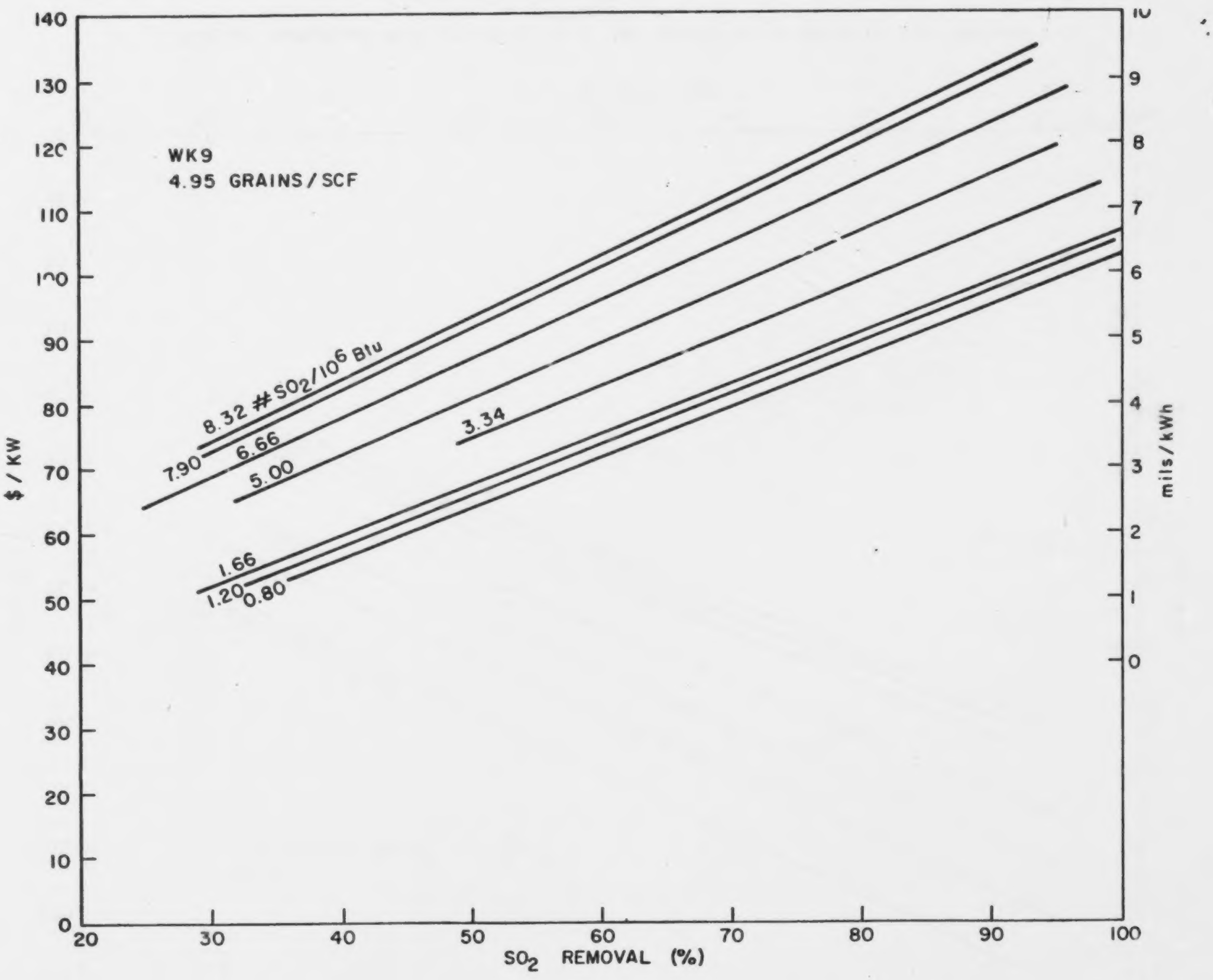
$CaCO_3$ in Limestone (% wt.)	97



Capital Investment and Operating Costs for Limestone Scrubbing vs. SO_2 Removal
FIGURE 2

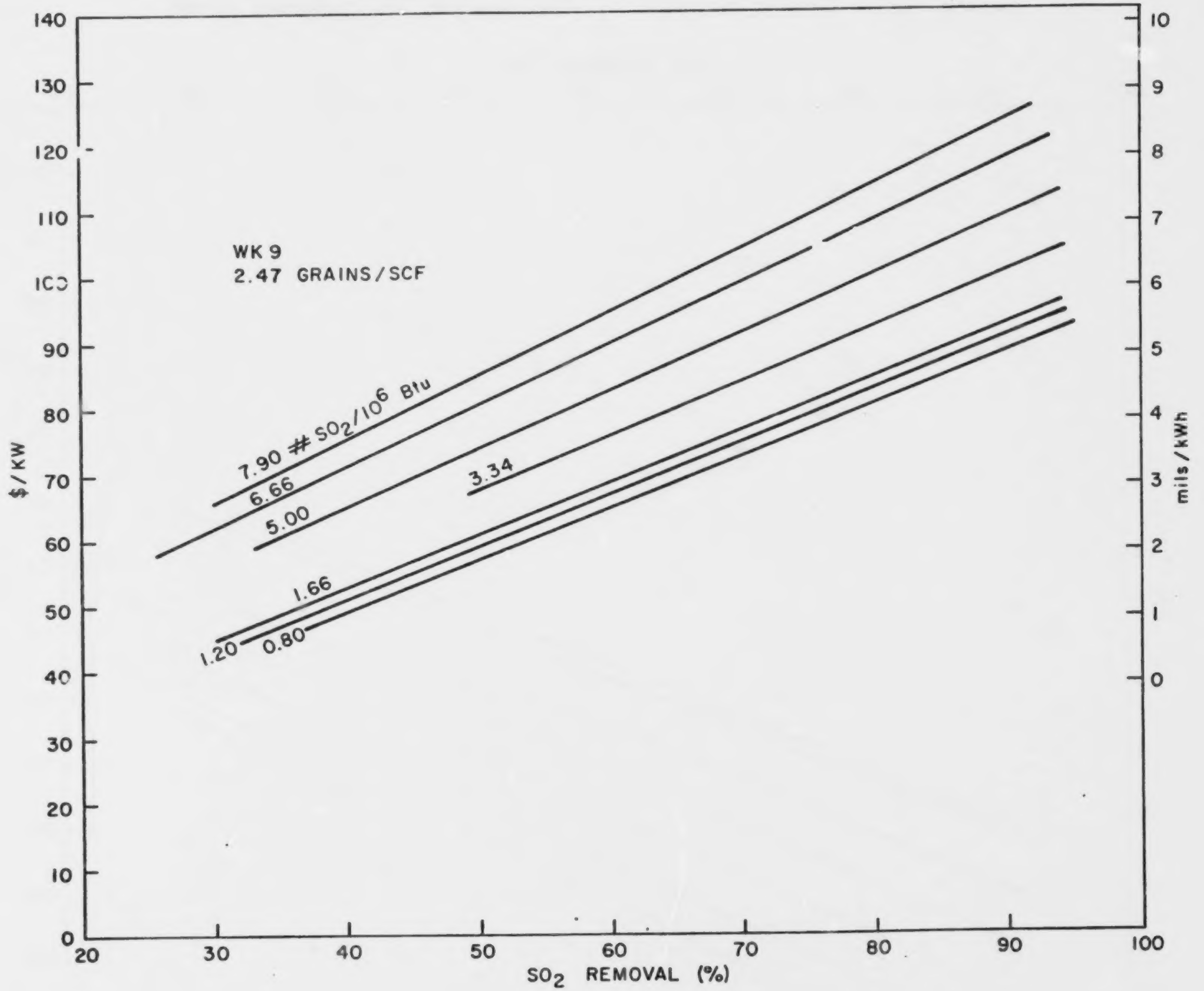


Capital Investment and Operating Costs for Limestone Scrubbing vs. SO_2 Removal
FIGURE 3

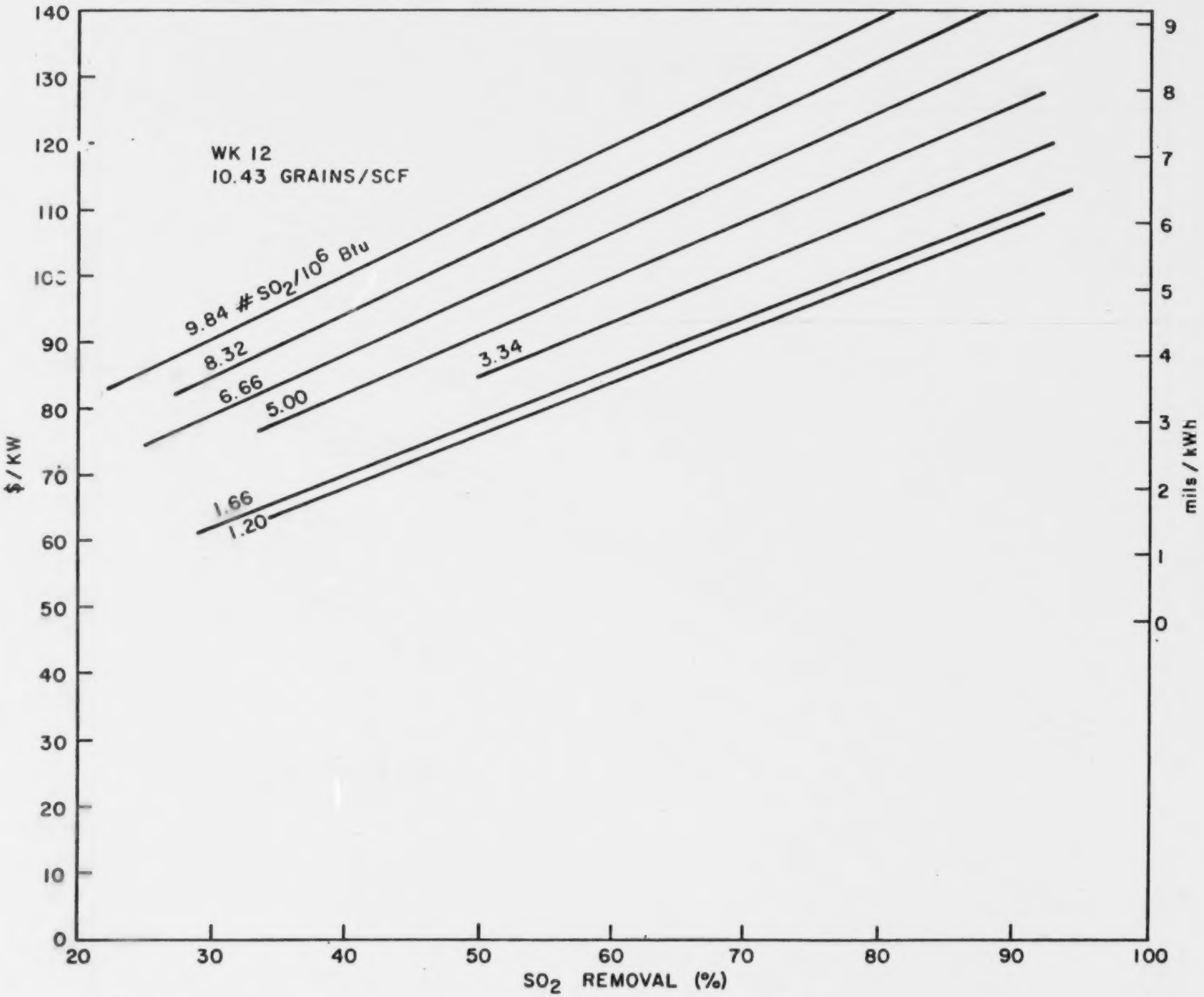


Capital Investment and Operating Costs for Limestone Scrubbing vs. SO_2 Removal
FIGURE 4

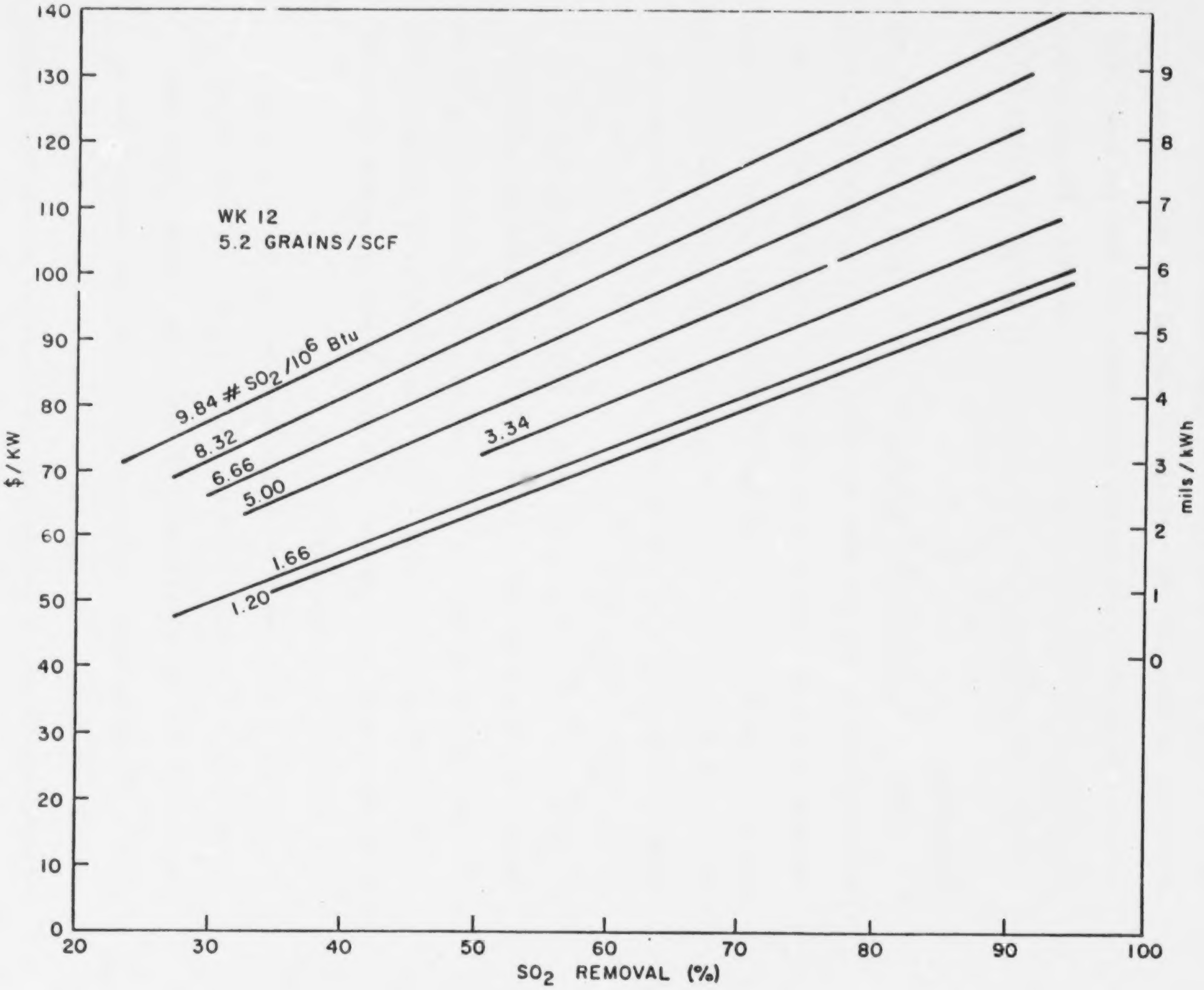
Capital Investment and Operating Costs for Limestone Scrubbing vs. SO_2 Removal
FIGURE 7



Capital Investment and Operating Costs for Limestone Scrubbing vs. SO_2 Removal
FIGURE 5



Capital Investment and Operating Costs for Limestone Scrubbing vs. SO_2 Removal
FIGURE 6


WK 12
5.2 GRAINS/SCF
9.84 # $SO_2/10^6$ Btu
8.32
6.66
5.00
3.34
1.66
1.20
$/KW
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
mils / kWh
0
1
2
3
4
5
6
7
8
9
20
30
40
50
60
70
80
90
100
SO_2 REMOVAL (%)

Coal-Cleaning Plant

The coal-cleaning plant is assumed to be a conventional heavy media system costing about $35 million. The input capacity is 1,800 TPH, consisting of three-600 TPH circuits with two of the three circuits operating three shifts per day for a minimum of 230 days per year. The annual output of clean coal is about 5.63 million tons. The yield, Btu recovery, and operating costs are summarized in Tables II through VII.

Discussion

Cases 1, 3, and 5 assume run-of-mine coal is fired in the two 1,000-MW units followed by flue gas desulfurization. The pulverized coal units were designed with a heat rate of 9,000 Btu/kWh and a capacity factor of 65 percent. A heat rate of 10,000 Btu/kWh and capacity factor of 45 percent was assumed for the cases where uncleaned coal was used. The gross annual generation decreased from a design output of 11.39 billion kWh to 7.88 billion kWh for these cases.

Cases 2, 4, and 6 assume 50 percent of the mineral matter and 60 percent of the pyritic sulfur was removed before combustion followed by flue gas desulfurization. The heat rate was held constant at 10,000 Btu/kWh. It was assumed that by burning a better quality fuel the capacity factor increased from 45 to 56 percent. The gross annual generation increased from 7.88 to 9.81 billion kWh.

In case 1 the power plant burned West Kentucky No. 11 with 20.5 percent ash, 4.5 sulfur, and 10,416 Btu per pound. The particulate emission to the TCA scrubber was 7.56 grains per standard cubic foot (SCF). The particulate emission leaving the scrubber was 0.04 grains per SCF, resulting in the required 99.5 percent removal. The sulfur dioxide emission to the scrubber was 8.6 pounds per million Btu requiring

TABLE II

SUMMARY

CASE	"2" (WK 11)
Yield Factor, % Weight, Y	85%
Recovery Factor, % Btu, R	96%
Btu Content ROM Coal, Btu/#, B_R	10,416
Btu Content Clean Coal, Btu/#, $B_C = \frac{B_R(R)}{Y}$	11,764
Hourly Input, ROM Coal, TPH	1,200
Hourly Output, Clean Coal, TPH	1,020
Total Capital Investment, $	35×10^6
Cost Per TPH ROM Coal Cap, $/TPH	29,200
Cost Per Annual Ton Clean Coal, $/TPH	$6.22
Fixed Charges on Capital $/Ton c.c.	1.33
O&M Cost Including Refuse Disposal, $/Ton c.c.	0.97
Cost of Preparation, $/Ton c.c. (P/C)	2.30
Cost of Btu Loss, $/Ton c.c.	1.12
Total Cost of Preparation, $/Ton c.c.	3.42
Cost of ROM Coal, $/Ton c.c.	22.08
Cost of Clean Coal, $/Ton	25.50
Cost of Preparation, $\$/10^6$ Btu, (C_P)	0.0978
Cost of Btu Loss, $\$/10^6$ Btu, (C_B)	0.0477
Total Cost of Prep, $\$/10^6$ Btu, (C_T)	0.1455
Cost of ROM Coal, $\$/10^6$ Btu, (C_R)	1.06
Cost of Clean Coal, $\$/10^6$ Btu (C_C)	1.2055
Cost of Clean Coal, $/Ton	28.36
Credit for Improved Heating Value, $/Ton	-2.86
Cost of Clean Coal, $/Ton	25.50
Total Cost of Preparation, Mils/kWh	1.46

TABLE III

ESTIMATED ANNUAL REVENUE REQUIREMENT

			$/Ton Clean Coal
LABOR COSTS			
SUPERVISION			.0500
OPERATION			.0827
MAINTENANCE			.1338
			.2665
UTILITIES & PROCESS RELATED COSTS			
POWER	9500 HP	0.020 $/KWH	.139 $/TON C.C.
WATER	7206 PM	0.020 $/K GAL.	.00085
MAGNETIC LOSS	1.5 #/TON	0.0325 $/#	.0574
FLOCCULANT	6. #/HR	1.50 $/#	.0088
LUBRICANT			.005
THERMAL DRYER	6.7 TPH	1.19 $/$10^6$ BTU	.184
REFUSE DISPOSAL	180 TPH	1.00 $/TON	.176
BTU LOSS	3000 BTU/#	1.06 $/$10^6$ BTU	1.123
MAINT. MATS.	50/50 WITH MAINT. LABOR		.1338
			1.8279
FIXED COSTS			
GEN. AD. EXP. (60%) & M LABOR)			.1299
PROPERTY TAXES & INS. (2.5% X PL. INV.)			.1554
PLANT DEPRECIATION STR. LINE (30 YR.)			.2072
CAPITAL CHARGE (11%)			.715
CONTINGENCY			.1208
			1.3283
TOTAL COST OF PREPARATION, $/TON C.C.			3.4227
ANNUAL PREP. COST			$19,269,801

TABLE IV

SUMMARY

CASE	4 (WK 9)
Yield Factor, % Weight, Y	85
Recovery Factor, % Btu, R	94
Btu Content ROM Coal, Btu/#, B_R	11,363
Btu Content Clean Coal, Btu/#, $B_C = B_R \frac{(R)}{Y}$	12,566
Hourly Input, ROM Coal, TPH	1200
Hourly Output, Clean Coal, TPH	1020
Total Capital Investment, $	35×10^6
Cost Per TPH ROM Coal Cap, $/TPH	$29,200
Cost Per Annual Ton Clean Coal, $/TPH	6.22
Fixed Charges on Capital $/Ton c.c.	1.33
O&M Cost Including Refuse Disposal, $/Ton c.c.	0.94
Cost of Preparation, $/Ton c.c. (P/C)	2.27
Cost of Btu Loss, $/Ton c.c.	1.43
Total Cost of Preparation, $/Ton c.c.	3.70
Cost of ROM Coal, $/Ton c.c.	20.00
Cost of Clean Coal, $/Ton	23.70
Cost of Preparation, $/10^6 Btu, ($C_P$)	0.0903
Cost of Btu Loss, $/10^6 Btu, ($C_B$)	0.0569
Total Cost of Prep, $/10^6 Btu, ($C_T$)	0.1472
Cost of ROM Coal, $/10^6 Btu, ($C_R$)	0.88
Cost of Clean Coal, $/10^6 Btu ($C_C$)	1.0272
Cost of Clean Coal, $/Ton	25.82
Credit for Improved Heating Value, $/Ton	2.12
Cost of Clean Coal, $/Ton	23.70
Total Cost of Preparation, Mils/kWh	1.47

TABLE V

WK 9

ESTIMATED ANNUAL REVENUE REQUIREMENT

	$ / Ton c.c.	
Labor Costs		
Supervision	.0500	
Operation	.0827	
Maintenance	.1338	
	.2665	
Utilities & Process Related Costs		
Power	.1390	
Water	.00085	
Magnetite loss 1.5 $\frac{\$}{\text{Ton}}$ 0.032 $\frac{\$}{\#}$	.0574	
Flocculant 6 $\frac{\#}{\text{HR}}$ 1.50 $\frac{\$}{\#}$	.0088	
Lubricant	.0050	
Thermal dryer 6.3 TPH 0.97 $\frac{\$}{10^6 \text{Btu}}$	.1501	
Refuse disposal 180 TPH 1.00 $\frac{\$}{\text{Ton}}$	.176	
Btu loss 4600 $\frac{\text{Btu}}{\#}$ 0.88 $\frac{\$}{10^6 \text{Btu}}$	1.4287	
Maintenance Material 50/50 with Maint. Labor	.1338	
	2.09965	
FIXED COSTS		
General Administrative Expense (60% O&M Labor)	.1299	
Property Taxes & Insurance (2.5% x Plt Inv.)	.1554	
Plant Depreciation (Str. line 30 yr.)	.2072	
Capital Charge (11%)	.715	
Contingency	.1208	
	1.3283	
	3.69415	20,799,754

TABLE VI

SUMMARY

CASE	6 (WK 12)
YIELD FACTOR, % WEIGHT, Y	85
RECOVERY FACTOR, % BTU, R	94
BTU CONTENT ROM COAL, BTU/#, B_R	9,538
BTU CONTENT CLEAN COAL, BTU/#, $B_C = \frac{B_R(R)}{Y}$	10,548
HOURLY INPUT, ROM COAL, TPH	1,200
HOURLY OUTPUT, CLEAN COAL, TPH	1,020
TOTAL CAPITAL INVESTMENT, $	35×10^6
COST PER TPH ROM COAL CAP, $/TPH	29,200
COST PER ANNUAL TON CLEAN COAL, $/TPH	6.22
FIXED CHARGES ON CAPITAL $/TON C.C.	1.33
O&M COST INCLUDING REFUSE DISPOSAL, $/TON C.C.	.92
COST OF PREPARATION, $/TON C.C. (P/C)	2.25
COST OF BTU LOSS, $/TON C.C.	1.05
TOTAL COST OF PREPARATION, $/TON C.C.	3.30
COST OF ROM COAL, $/TON C.C.	15.00
COST OF CLEAN COAL, $/TON	18.30
COST OF PREPARATION, $/10^6 BTU, ($C_P$)	0.1066
COST OF BTU LOSS, $/10^6 BTU, ($C_B$)	0.0498
TOTAL COST OF PREP, $/10^6 BTU, ($C_T$)	0.1564
COST OF ROM COAL, $/10^6 BTU, ($C_R$)	0.786
COST OF CLEAN COAL, $/10^6 BTU ($C_C$)	0.9424
COST OF CLEAN COAL, $/TON	19.89
CREDIT FOR IMPROVED HEATING VALUE, $/TON	1.59
COST OF CLEAN COAL, $/TON	18.30
TOTAL COST OF PREPARATION, MILS/KWH	1.56

TABLE VII

VK 12

ESTIMATED ANNUAL REVENUE REQUIREMENT

		$\frac{\$}{\text{TON}}$ C.C.
LABOR COSTS		
SUPERVISION		0.0500
OPERATION		0.0827
MAINTENANCE		0.1338
		0.2665
UTILITIES & PROCESS RELATED COSTS		
POWER (9500 HP)	0.020 $\frac{\$}{\text{KWH}}$	0.139
WATER 720 GPM	0.010 $\frac{\$}{\text{K GAL}}$	0.00085
MAGNETITC 1.5 $\frac{\$}{\text{TON}}$	0.032 $\frac{¢}{\#}$	0.0574
FLOCCULANT		0.0088
LUBRICANT		0.0050
THERMAL DRYER 7.45 TPH	0.906 $\frac{\$}{10^6 \text{BTU}}$	0.1340
REFUSE DISPOSAL 180 TPH	1.00 $\frac{\$}{\text{TON}}$	0.176
BTU LOSS 3800 $\frac{\text{BTU}}{\#}$	0.786 $\frac{\$}{10^6 \text{BTU}}$	1.05
MAINTENANCE MATERIAL 5/50 MAINT. LABOR		.1338
		1.70485
FIXED COSTS		
GENERAL ADMINISTRATIVE EXPENSE (60% O&M LABOR)		.1299
PROPERTY TAXES & INSURANCE (2.5% x PLT. INV.)		.1554
PLT. DEPRECIATION (STR. LINE 30 YR)		.2072
CAPITAL CHARGE (11%)		.715
CONTINGENCY		.1208
		1.3283
		3.29965
		18,609,121

an 86 percent removal efficiency to achieve the 1.2 pound standard. The TCA scrubber system cost $244.5 million. The power plant production cost was $98.19 million per year. A penalty of $6.81 per ton was assessed for the use of this coal resulting in an additional annual cost of $25.74 million. The scrubber operating cost was $58.3 million per year. The total generation cost was $182.2 million per year or 23.1 mils per kWh.

In case 2 the West Kentucky No. 11 coal was beneficiated in a heavy media coal-cleaning plant. The ash and sulfur content were reduced to 10.3 and 2.7 percent, respectively. The yield from the coal-cleaning plant was 85 percent. The cleaning plant was assumed to improve the heating value of the coal from 10,416 to 11,764 Btu per pound with a Btu recovery of 96 percent.

When fired by the power plant the particulate emission to the TCA scrubber was 3.78 grains per SCF. The particulate leaving the scrubber was 0.02 grains per SCF (99.5 percent removal). The sulfur dioxide emission to the scrubber was 4.59 pounds per million Btu requiring a 74 percent efficiency to achieve the 1.2 pound standard. The cost of the coal-cleaning plant was $35 million and the processing cost per ton of cleaned coal was $3.42. The scrubber cost was $192.6 million. The power plant production cost was $125.1 million per year. A penalty was not assessed against the washed coal. The scrubber operating cost was $55.92 million per year. The total generation cost was $177.1 million per year or 18.1 mils per kWh, compared to 23.1 for case 1.

In case 3 the power plant burned West Kentucky No. 9 with 14.85 percent ash, 4.5 percent sulfur, and 11,363 Btu per pound. The particulate emission to the TCA scrubber was 4.95 grains per standard cubic foot (SCF).

The particulate emission leaving the scrubber was 0.02 grains per SCF (99.5 percent removal). The sulfur dioxide emission to the scrubber was 7.9 pounds per million Btu. An 85 percent removal efficiency would achieve the 1.2 pound standard. The TCA scrubber system cost $231.5 million. The power plant production cost was $81.65 million per year. A penalty of $2.26 per ton was assessed for the use of this coal resulting in an additional annual cost of $7.5 million. The scrubber operating cost was $57.6 million per year. The total generation cost was $146.75 million per year or 18.5 mils per kWh.

In case 4 the West Kentucky No. 9 coal was beneficiated in a heavy media coal-cleaning plant. The ash and sulfur contents were reduced to 7.5 and 2.7 percent, respectively. The yield from the coal-cleaning plant was 85 percent. The cleaning plant was assumed to improve the heating value of the coal from 11,363 to 12,566 Btu per pound with a Btu/recovery of 94 percent. When fired by the power plant the particulate emission to the TCA scrubber was 0.01 grains per SCF (99.5 percent removal). The sulfur dioxide emission to the scrubber was 4.3 pounds per million Btu requiring a 72 percent efficiency to achieve the 1.2 pound standard. The cost of the coal-cleaning plant was $35 million and the processing cost per ton of cleaned coal was $3.70. The scrubber cost was $203.7 million. The power plant production cost was $108.7 million per year. A penalty was not assessed against the washed coal. The scrubber operating cost was $60.8 million per year. The total generation cost was $169.5 million per year or 17.3 mils per kWh, compared to 18.5 for case 3.

In case 5 the power plant burned West Kentucky No. 12 coal with 26.05 percent ash, 4.7 percent sulfur, and 9,538 Btu per pound. The particulate emission to the TCA scrubber was 10.43 grains per SCF. The particulate emission leaving the scrubber was 0.03 grains per SCF (99.5 percent removal). The sulfur dioxide emission to the scrubber was 9.84 pounds per million Btu requiring an 88 percent removal efficiency to achieve the 1.2 pound standard. The TCA scrubber system cost $274.1 million. The power plant production cost was $72.88 million per year. A penalty of $11.22 per ton was assessed for the use of this coal resulting in an additional annual cost of $46.3 million. The scrubber operating cost was $67.8 million per year. The total generation cost was $187.0 million per year or 23.7 mils per kWh.

In case 6 the West Kentucky No. 12 coal was beneficiated in a heavy media cleaning plant. The ash and sulfur content were reduced to 13 and 2.6 percent, respectively. The yield from the coal-cleaning plant was 85 percent. The cleaning plant was assumed to improve the heating value of the coal from 9,538 to 10,548 Btu per pound with a Btu recovery of 94 percent. When fired by the power plant the particulate emission to the TCA scrubber was 5.2 grains per SCF. The particulate leaving the scrubber was 0.03 grains per SCF (99.5 percent removal). The sulfur dioxide emission to the scrubber was 4.9 pounds per million Btu requiring a 77 percent efficiency to achieve the 1.2 pound standard. The cost of the coal-cleaning plant was $35 million and the processing cost per ton of cleaned coal was $3.30. The scrubber cost was $203.7 million. The power plant production cost was $100 million per year. A penalty was not assessed against the washed coal. The scrubber operating cost was $56.9 million per year. The total generation cost was $156.9 million per year or 16 mils per kWh, compared to 23.7 mils per kWh, for case 5. These cases are summarized in Tables VIII through XVI.

TABLE VIII

CASE 1

ROM COAL ⟶ 2 - 1000 MW UNITS ⟶ FGD ⟶

ROM COAL	2 - 1000 MW UNITS	FGD
4.5% S 20.55% ASH 10,416 $\frac{\text{BTU}}{\#}$	8.6 $\frac{\#SO_2}{10^6\text{BTU}}$ 7.56 $\frac{\text{GRAINS}}{\text{SCF}}$	1.29 $\frac{\#SO_2}{10^6\text{BTU}}$ 0.04 $\frac{\text{GRAINS}}{\text{SCF}}$

CAPACITY FACTOR	45%
GENERATION	7.88×10^9 $\frac{\text{KWH}}{\text{YR}}$
HEAT RATE	10,000 $\frac{\text{BTU}}{\text{KWH}}$
FUEL CONSUMPTION	3.78×10^6 $\frac{\text{TONS}}{\text{YR}}$
FUEL COST	83.46×10^6 $\frac{\$}{\text{YR}}$
PRODUCTION COST	98.19×10^6 $\frac{\$}{\text{YR}}$
PENALTY (A + S) > 17.5%	25.74×10^6 $\frac{\$}{\text{YR}}$
FGD INVESTMENT COST	122.24 $\frac{\$}{\text{KW}}$ = 244.5×10^6 \$
FGD REVENUE REQUIREMENT	0.0074 $\frac{\$}{\text{KWH}}$ = 58.3×10^6 \$
TOTAL GENERATION COST	182.23×10^6 $\frac{\$}{\text{YR}}$ = 23.1 $\frac{\text{MILS}}{\text{KWH}}$

TABLE IX

CASE 2

$\longrightarrow$ ROM COAL $\longrightarrow$ PREP PLT $\longrightarrow$ POWER PLT $\longrightarrow$ FGD $\longrightarrow$

ROM COAL	PREP PLT	POWER PLT	FGD
4.5% S	2.7% S	$4.59 \frac{\#SO_2}{10^6 Btu}$	$1.29 \frac{\#SO_2}{10^6 Btu}$
20.55% Ash	10.3% Ash		
$10,416 \frac{Btu}{\#}$	$11,764 \frac{Btu}{\#}$	$3.78 \frac{Grains}{SCF}$	$0.02 \frac{Grains}{SCF}$

Prep Plt Investment	35×10^6 \$
Prep Cost ± 3.42 \$/Ton Clean Coal	
Prep Cost	$19.3 \times 10^6 \frac{\$}{YR}$
Capacity Factor	56%
Generation	$9.81 \times 10^9 \frac{KWH}{YR}$
Heat Rate	$10,000 \frac{Btu}{KWH}$
Fuel Consumption	$4.17 \times 10^6 \frac{Tons}{YR}$
Fuel Cost	$106.34 \times 10^6 \frac{\$}{YR}$
Production Cost (85% Fuel Cost)	$125.1 \times 10^6 \frac{\$}{YR}$
FGD Investment Cost	$96.30 \frac{\$}{KW}$ $= 192.6 \times 10^6$ \$
FGD Revenue Requirement	$0.0057 \frac{\$}{KWH}$ $= 55.92 \times 10^6 \frac{\$}{YR}$
Total Generation Cost	$177.1 \times 10^6 \frac{\$}{YR}$ $= 18.1 \frac{MILS}{KWH}$

TABLE X

COMPARISON
FGD ONLY WITH COAL CLEANING & FGD
WEST KENTUCKY NO. 11
85% SO_2 REMOVAL

CASE 1 ROM COAL ⟶ 2 @ 1000 MW UNITS ⟶ FGD ⟶

CASE 2 ROM COAL ⟶ PREP PLT ⟶ POWER PLT ⟶ FGD ⟶

PREP PLT INVESTMENT, 10^6 \$		35.0
PREP COST @ 3.42 $\frac{\$}{TON}$ CLEAN COAL		
PREP COST, $10^6 \frac{\$}{YR}$		19.3
GENERATION, $10^9 \frac{KWH}{YR}$	7.88	9.81
PRODUCTION COST, $10^6 \frac{\$}{YR}$	98.19	125.1
PENALTY (A + S > 17.5%), $10^6 \frac{\$}{YR}$	25.74	
FGD INVESTMENT, 10^6 \$	244.5	192.6
FGD REVENUE REQUIREMENT, $10^6 \frac{\$}{YR}$	58.3	55.9
TOTAL GENERATION COST, $10^6 \frac{\$}{YR}$	182.2	177.1
, $\frac{MILLS}{KWH}$	23.1	18.1

TABLE XI

CASE 3

ROM COAL ⟶ 2 - 1000 MW UNITS ⟶ FGD ⟶

4.5% S 14.85% Ash 11,363 $\frac{\text{Btu}}{\#}$	7.9 $\frac{\#SO_2}{10^6 \text{Btu}}$ 4.95 $\frac{\text{Grains}}{\text{SCF}}$	1.19 $\frac{\#SO_2}{10^6 \text{Btu}}$ 0.02 $\frac{\text{Grains}}{\text{SCF}}$

Capacity Factor	45%
Generation	$7.88 \times 10^9 \frac{\text{KWH}}{\text{YR}}$
Heat Rate	$10,000 \frac{\text{Btu}}{\text{KWH}}$
Fuel Consumption	$3.47 \times 10^6 \frac{\text{Ton}}{\text{YR}}$
Fuel Cost	$69.4 \times 10^6 \frac{\$}{\text{YR}}$
Production Cost	$81.65 \times 10^6 \frac{\$}{\text{YR}}$
Penalty (A + S) > 17.5%	$7.5 \times 10^6 \frac{\$}{\text{YR}}$
FGD Investment Cost	$115.75 \frac{\$}{\text{KW}}$ 231.5×10^6 \$
FGD Revenue Requirement	$0.0073 \frac{\$}{\text{KWH}}$ $57.6 \times 10^6 \frac{\$}{\text{YR}}$
Total Generation Cost	$146.75 \times 10^6 \frac{\$}{\text{YR}}$ $= 18.5 \frac{\text{MILS}}{\text{KWH}}$

TABLE XII

CASE 4

ROM COAL →	PREP PLT →	POWER PLT →	FGD →
4.5% S	2.7% S	$4.3 \frac{\#SO_2}{10^6 Btu}$	$1.19 \frac{\#SO_2}{10^6 Btu}$
14.85% Ash	7.4% Ash		
$11,363 \frac{Btu}{\#}$	$12,566 \frac{Btu}{\#}$	$2.47 \frac{Grains}{SCF}$	$0.01 \frac{Grains}{SCF}$

Prep Plt Investment	35×10^6
Prep Cost @ $3.70 \frac{\$}{Ton}$ Clean Coal	
Prep Cost	20.8×10^6
Capacity Factor	56%
Generation	$9.81 \times 10^9 \frac{KWH}{YR}$
Heat Rate	$10,000 \frac{Btu}{KWH}$
Fuel Consumption	$3.9 \times 10^6 \frac{Tons}{YR}$
Fuel Cost	$92.43 \times 10^6 \frac{\$}{YR}$
Production Cost	$108.7 \times 10^6 \frac{\$}{YR}$
FGD Investment Cost	$101.86 \frac{\$}{KW}$ $= 203.7 \times 10^6$
FGD Revenue Requirement	$0.0062 \frac{\$}{KWH}$ $= 60.8 \times 10^6 \frac{\$}{YR}$
Total Generation Cost	$169.5 \times 10^6 \frac{\$}{YR}$ $= 17.3 \frac{MILS}{KWH}$

TABLE XIII

COMPARISON
FGD ONLY WITH COAL CLEANING & FGD
WEST KENTUCKY NO. 9
85% SO_2 REMOVAL

CASE 3 ROM COAL ------→ 2@ 1000 MW UNITS ——→ FGD ——→

CASE 4 ROM COAL ——→ PREP PLT ——→ POWER PLT ——→ FGD ——→

PREP PLT INVESTMENT, 10^6 \$		35
PREP COST @ 3.70 $\frac{\$}{TON}$ CLEAN COAL		
PREP COST, 10^6 $\frac{\$}{YR}$		20.8
GENERATION, 10^9 $\frac{KWH}{YR}$	7.88	9.81
PRODUCTION COST, 10^6 $\frac{\$}{YR}$	81.65	108.7
PENALTY (A + S > 17.5%), 10^6 $\frac{\$}{YR}$	7.5	
FGD INVESTMENT, 10^6 \$	231.5	203.7
FGD REVENUE REQUIREMENT, 10^6 $\frac{\$}{YR}$	57.6	60.8
TOTAL GENERATION COST, 10^6 $\frac{\$}{YR}$	146.75	169.5
, $\frac{MILLS}{KWH}$	18.5	17.3

TABLE XIV

CASE 5

ROM COAL ⟶ 2 - 1000 MW UNITS ⟶ FGD ⟶

4.7% S 26.05% Ash 9,538 $\frac{\text{Btu}}{\#}$	$9.84 \frac{\#SO_2}{10^6 \text{Btu}}$	$1.48 \frac{\#SO_2}{10^6 \text{Btu}}$
	$10.43 \frac{\text{Grains}}{\text{SCF}}$	$0.03 \frac{\text{Grains}}{\text{SCF}}$
		(88% Removal) $1.2 \frac{\#SO_2}{10^6 \text{Btu}}$

Capacity Factor	45%
Generation	$7.88 \times 10^9 \frac{\text{KWH}}{\text{YR}}$
Heat Rate	$10,000 \frac{\text{Btu}}{\text{KWH}}$
Fuel Consumption	$4.13 \times 10^6 \frac{\text{Tons}}{\text{YR}}$
Fuel Cost	$61.95 \times 10^6 \frac{\$}{\text{YR}}$
Production Cost	$72.88 \times 10^6 \frac{\$}{\text{YR}}$
Penalty (A + S > 17.5%)	$45.3 \times 10^6 \frac{\$}{\text{YR}}$
FGD Investment	$137.05 \frac{\$}{\text{KW}}$ $= 274.10 \times 10^6$ \$
FGD Revenue Requirement	$.0086 \frac{\$}{\text{KWH}}$ $= 67.8 \times 10^6 \frac{¢}{\text{YR}}$
Total Generation Cost	$187.0 \times 10^6 \frac{\$}{\text{YR}}$ $= 23.7 \frac{\text{MILLS}}{\text{KWH}}$

TABLE XV

CASE 6

ROM COAL $\longrightarrow$ PREP PLT $\longrightarrow$ POWER PLT $\longrightarrow$ FGD $\longrightarrow$

ROM COAL	PREP PLT	POWER PLT	FGD
4.7% S	2.6% S	$4.9 \frac{\#SO_2}{10^6\text{Btu}}$	$1.48 \frac{\#SO_2}{10^6\text{Btu}}$
26.05 % Ash	13% Ash		
$9538 \frac{\text{Btu}}{\#}$	$10,548 \frac{\text{Btu}}{\#}$	$5.2 \frac{\text{Grains}}{\text{SCF}}$	$0.03 \frac{\text{Grains}}{\text{SCF}}$
			76%
			$1.2 \frac{\#SO_2}{10^6\text{Btu}}$

Prep Plt Investment	35×10^6
Prep Cost @ $3.30 \frac{\$}{\text{TON}}$ C.C.	
Prep Cost	$18.6 \times 10^6 \frac{\$}{\text{YR}}$
Capacity Factor	56%
Generation	$9.81 \times 10^9 \frac{\text{KWH}}{\text{YR}}$
Heat Rate	$10,000 \frac{\text{Btu}}{\text{KWH}}$
Fuel Consumption	$4.65 \times 10^6 \frac{\text{Tons}}{\text{YR}}$
Fuel Cost	$85.1 \times 10^6 \frac{\$}{\text{YR}}$
Production Cost	$100 \times 10^6 \frac{\$}{\text{YR}}$
FGD Investment	$101.86 \frac{\$}{\text{KW}}$
	$203.7 \times 10^6 \frac{\$}{\text{YR}}$
FGD Revenue Requirement	$0.0068 \frac{\$}{\text{KWH}}$
	$56.9 \times 10^6 \frac{\$}{\text{YR}}$
Total Generation Cost	$156.9 \times 10^6 \frac{\$}{\text{YR}}$
	$16 \frac{\text{MILS}}{\text{KWH}}$

TABLE XVI

COMPARISON
FGD ONLY WITH COAL CLEANING & FGD
WEST KENTUCKY NO. 12
85% SO_2 REMOVAL

CASE 5 ROM COAL ——→ 2@ 1000 MW UNITS ——→ FGD ——→

CASE 6 ROM COAL ——→ PREP PLT ——→ POWER PLT ——→ FGD ——→

PREP PLT INVESTMENT, 10^6 \$		35
PREP COST @ 3.30 $\frac{\$}{TON}$ CLEAN COAL		
PREP COST, 10^6 $\frac{\$}{YR}$		18.6
GENERATION, 10^9 $\frac{KWH}{YR}$	7.88	9.81
PRODUCTION COST, 10^6 $\frac{\$}{YR}$	72.88	100
PENALTY (A + S > 17.5%), 10^6 $\frac{\$}{YR}$	46.3	
FGD INVESTMENT, 10^6 \$	274.1	203.7
FGD REVENUE REQUIREMENT, 10^6 $\frac{\$}{YR}$	67.8	56.9
TOTAL GENERATION COST, 10^6 $\frac{\$}{YR}$	187.0	156.9
, $\frac{MILS}{KWH}$	23.7	16

Conclusions

The combination of coal cleaning and flue gas desulfurization is a better choice than scrubbers alone for the three coals studied. Precombustion cleaning provides some flexibility in operating the scrubber and reduces the capital investment and operating costs for the absorbent handling and preparation system, and for sludge disposal. Generally, these savings will cover the cost of the coal preparation plant. Moreover, if EPA requires chemical fixation of scrubber sludge, the economics will tilt more in favor of the combination of precombustion cleaning and flue gas desulfurization. The greatest potential savings attributable to coal cleaning are reduced maintenance costs and increased rated capacity. Precombustion cleaning would allow an increase in availability and capacity, and reduced operating costs. Therefore, coal cleaning is an attractive approach to achieve energy and environmental goals.

THE ECONOMICS OF BENEFICIATING AND MARKETING HIGH-SULFUR IOWA COAL

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ABSTRACT

A mathematical programming model is used to evaluate alternative coal transportation, coal beneficiation, and coal handling systems. The objective of the analysis is to find the minimum-cost method of transporting and distributing coal to supply Iowa's projected 1980 coal consumption and, at the same time, meet the sulfur dioxide emission standards and constraints on Iowa mining capacity. The model includes 33 potential origins of coal for the identified 46 major coal users in Iowa. The 1980 projected coal requirements are specified in Btu's rather than tons to account for the differences in heating value of coal from different origins. The projected Btu requirements can be satisfied by obtaining coal directly from seven existing out-of-state coal sources or from two existing underground mines in Iowa. Coal from 24 potential Iowa strip mine locations can be used only if it is cleaned at one of eight potential coal beneficiation plant locations. Each coal user can blend two or more coals to meet its sulfur dioxide emission standard.

The model includes six possible modes of coal transport. These include truck, barge, single-car rail, 15-car rail, 50-car rail, and 100-car unit train.

The model minimizes the delivered cost of coal to the user subject to Btu requirements and SO_2 constraints. The delivered cost includes the FOB mine price of the coal, beneficiation costs if the coal is cleaned, all transportation and variable receiving costs, and any additional investments in capacity required to receive larger size rail shipments.

Eight computer solutions obtained in the analysis were based on alternative sets of coal prices, rail rates, and truck weight limits.

The U.S. Environmental Protection Agency has adopted a national standard which limits sulfur dioxide emissions to 1.2 pounds of SO_2 per million Btu of heat at coal-fired stationary boilers with a heat input of > 250 million Btu constructed after August 17, 1971 (U.S. Environmental Protection Agency, 1971). Assuming 10,000 Btu per pound, only coal with $\leq$ 0.6 percent sulfur could be burned in these boilers under this emission standard.

Individual states, counties or cities may establish SO_2 emission standards for smaller boilers and boilers constructed before August 17, 1971. The current SO_2 emission standards for these boilers in Iowa are 5, 6, or 8 pounds of SO_2 per million Btu, depending upon the location of the boiler. Assuming 10,000 Btu per pound, only those coals with sulfur contents $\leq$ 2.5, 3.0, or 4.0 percent, respectively, could be burned in these boilers under these emission standards.

Strippable coal reserves in Iowa typically average between 3.1 and 5.8 percent sulfur (Avcin, 1976). This, in part, explains why Iowa coal production declined from over 1 million tons in 1971 to 540,000 tons in 1976. Only 259,000 tons of Iowa coal were strip mined in 1975 (U.S. Department of the Interior, 1971, 1976, 1977).

One method of improving the competitive position of this high sulfur coal may be to reduce the content of sulfur and other impurities. An experimental coal beneficiation plant operated by Iowa State University--the only such plant in Iowa--has shown that the sulfur content of Iowa coal can be reduced on the average about 35 percent (Grieve and Fisher, 1978). If coal beneficiation will improve the competitive market position of the high sulfur coal, the optimal number and location of beneficiation plants must be determined.

Another alternative for improving the competitive market position of high sulfur coal is to reduce the cost of transporting coal to users. Possible improvements in coal transportation include larger size rail shipments such as 15- and 50-car units, alternative types of trucks, and inter-modal truck-rail combinations.

Method of Analysis

The purpose of this paper is to present estimates of the impact of alternative transportation and coal beneficiation systems and coal prices on the marketability of high sulfur Iowa coal. A mixed integer-linear programming model is specified to evaluate the feasibility of mining and beneficiating Iowa coal for use by utility and industrial coal users in Iowa under alternative combinations of coal prices and rail rates. The model selects the least cost number and location of beneficiation plants from 8 possible sites. The objective of the analysis is to find the minimum cost method of supplying Iowa's coal needs, subject to constraints on mining capacity, rail receiving capacity of Iowa coal users, beneficiation plant capacity, sulfur dioxide emission standards, and projected 1980 coal consumption in Iowa. The model includes 33 potential sources of coal for the 46 major utility and industrial coal users in Iowa. The projected 1980 coal consumption by each user is specified in heating units, rather than tons, to account for differences in the heating value of coal from different sources. User Btu requirements can be satisfied by obtaining coal directly from the two existing Iowa underground mines or from the seven out-of-state sources of coal. Because of its high sulfur content, coal from 24 potential strip mine locations (Avcin, 1976 and Lemish and Sendlein, 1977) in a 3½-county area in Iowa (Figure 1) can be used, only if it is beneficiated at one of the 8 possible beneficiation plant sites. The average sulfur and Btu content of the coal at these 24 potential strip mine locations is presented in Table 1.

In addition to meeting its projected 1980 Btu requirement, each user must satisfy the limits on sulfur dioxide emissions at each user location. Each user, however, can blend coal from two or more sources to meet its emission standard.

The supply of coal at the Iowa and Northern Missouri sources is constrained by assumed annual mining capacities and estimated coal reserves. Because Iowa consumes only a small percentage of the total production of the 6 remaining out-of-state coal origins, the supply capacity of these 6 sources is not constrained in the model.

The model includes 6 possible modes of transport from sources to users in 5 alternative computer solutions. The possible modes are barge, truck, single-car rail, 15-car rail, 50-car rail, and 100-car unit train. Each user has the option of receiving coal by the least-cost mode or combination of modes, subject to its existing rail receiving capacity. All users are given access to estimated truck rates from Iowa and Northern Missouri coal mines. Barge transportation is available only to users with existing barge receiving capabilities. The 4 possible modes of transport from Iowa coal

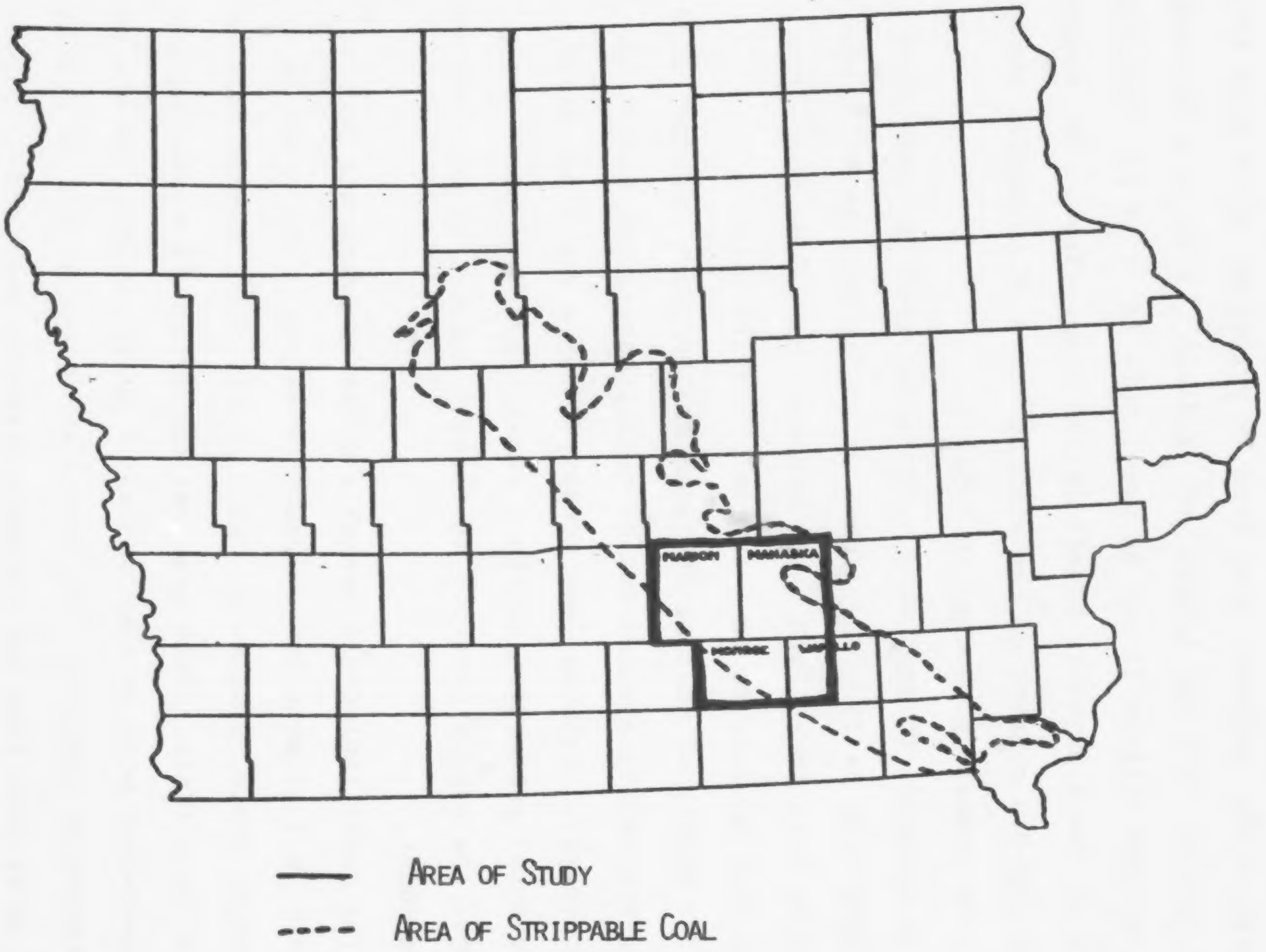
MARION
MAHASKA
MONROE
WAPELLO
AREA OF STUDY
AREA OF STRIPPABLE COAL

Figure 1. The selected Iowa coal-producing area.

Origin	Btu per pound	Percent sulfur content	Estimated 1977 FOB mine prices[a]	FOB mine prices based on average Iowa mining costs[a]	FOB mine prices based on high Iowa mining costs[a]
Sheridan, Wyoming	9,300	0.70	$12.65	$12.65	$12.65
Gillette, Wyoming	8,100	0.48	7.65	7.65[b]	7.65[b]
	8,100	0.48	7.15[b,c]	7.15[b,c]	7.15[b,c]
	8,100	0.48	6.40[d]	6.40[d]	6.40[d]
Canton, Illinois	11,000	3.25	24.70	24.70	24.70
Sparta, Illinois	11,400	2.90	22.20	22.20	22.20
West Harrisburg, Illinois	12,455	1.97	23.35	23.35	23.35
Nortonville, Kentucky	11,400	2.50	22.33	22.33	22.33
Unionville, Missouri[e]	10,500	2.62	20.16	21.35	24.90
Iowa Underground Mines					
Mine I	9,600	2.75	15.72	15.72	15.72
Mine II	10,225	4.60	13.53	13.53	13.53
Potential Iowa Strip Mines					
9 sites	9,794	5.25	14.95	16.87	19.60
3 sites	9,851	5.33	14.89	16.81	19.54
4 sites	10,348	5.83	14.55	16.47	19.20
1 site	10,900	5.60	14.70	16.62	19.35
1 site	10,181	3.24	16.91	18.83	21.56
2 sites	10,798	3.11	17.09	19.01	21.74
2 sites	10,294	5.49	14.78	16.70	19.43
2 sites	11,549	4.27	15.75	17.67	20.40

[a] The estimated per ton reclamation costs included in the strip mine prices are as follows: $0.15 for Wyoming, $0.70 for Illinois, $0.83 for Kentucky, and $1.93 for both Missouri and Iowa; these reclamation costs were weighted by the percentage of total coal production that is strip mined.

[b] Required annual volume of 500,000 - 1,500,000 tons.

[c] Shipments in 50- or 100-car trains.

[d] Required annual volume greater than 1,500,000 tons shipped in 100-car trains.

[e] Cleaned coal.

Table 1. Estimated FOB mine coal prices based on coal bids and on estimated Iowa mining and reclamation costs, by coal origin in dollars per ton, 1977.

beneficiation plants to users included in the model are truck, single-car rail, 15-car rail, and 50-car rail. Each user is restricted to its existing rail receiving capacity, unless it incurs an additional annual fixed cost for expanding to the next larger rail receiving capacity. If the projected 1980 coal consumption would provide less than one shipment per month at the next larger shipment size or the user has historically received all of its coal by truck and (or) barge, the user was not given the opportunity to increase its rail receiving capacity.

The delivered cost of beneficiated Iowa coal includes the FOB mine price of raw coal, the total annual cost of constructing a beneficiation plant, variable operating and maintenance costs of beneficiating the coal, the cost of transporting raw Iowa coal from the mine to the beneficiation plant, the cost of transporting the refuse from the beneficiation plant to the mine, and the cost of transporting the cleaned coal from the beneficiation plant to the user location.

The model uses continuous variables for the mining, transportation, and beneficiation activities and zero-one integer variables for the construction of beneficiation plants and the expansion of rail receiving capacity at users. The model can be summarized as follows:

$$
\begin{aligned}
(1)\quad \text{Minimize } Z = {} & \sum_{i} P_i M_i \\
& + \sum\sum\sum_{ikm} a_{ikm} U_{ikm} + \Psi \sum\sum\sum\sum_{ijkm} b_{ij} V_{ijkm} \\
& + (\Psi - 1) \sum\sum\sum\sum_{ijkm} c_{ij} V_{ijkm} \\
& + h \sum\sum\sum\sum_{ijkm} V_{ijkm} + \sum\sum\sum\sum_{ijkm} d_{jkm} V_{ijkm}
\end{aligned}
$$

$$+ \sum_j FC_j Y_j + \sum_k EC_k X_k \quad .$$

where

Z = total cost of coal unloaded at user locations,

P_i = price per unit of coal at origin i,

M_i = volume of coal supplied by origin i,

a_{ikm} = transportation plus variable receiving cost per unit of coal shipped from origin i directly to user k by mode m,

U_{ikm} = volume shipped from origin i directly to user k by mode m,

Ψ = inverse of the fractional weight recovery at beneficiation plants,

b_{ij} = transportation cost per unit of coal shipped from origin i to beneficiation plant site j,

V_{ijkm} = volume of clean coal equivalent shipped from origin i through beneficiation plant site j to user k by mode m,

c_{ij} = transportation cost per unit of refuse and fines shipped from beneficiation plant site j to mine i,

h = variable beneficiation cost per unit of clean coal,

d_{jkm} = transportation plus variable receiving cost per unit of clean coal shipped from beneficiation plant site j to user k by mode m,

FC_j = annual fixed cost of establishing a beneficiation plant at site j,

Y_j = (0, 1), a binary variable; if site j is used, $Y_j = 1$, otherwise $Y_j = 0$.

EC_k = annual fixed cost of expanding the rail receiving capacity of user k to the next largest size,

X_k = (0, 1) a binary variable; if user k expands its rail receiving capacity, $X_k = 1$, otherwise $X_k = 0$.

The following constraints were imposed on the model.

The annual volume of coal shipped from an origin cannot exceed the total annual production capacity of that origin.

(2) $$\sum_{km}\sum U_{ikm} + \Psi\sum_{jkm}\sum\sum V_{ijkm} = M_i \leq MC_i$$

where MC_i = total annual production capacity of origin i.

The annual volume of coal processed at a beneficiation plant site cannot exceed the annual beneficiation plant capacity.

(3) $$\sum_{ikm}\sum\sum V_{ijkm} \leq BC \text{ for all } j$$

where BC = annual beneficiation plant capacity in units of clean coal.

The projected consumption of coal at each user must be satisfied. This projected consumption was specified in heating units rather than tons to account for differences in the heating value of coals from different origins.

(4) $$\sum_{im}\sum \beta_i U_{ikm} + \sum_{ijm}\sum\sum \gamma_i V_{ijkm} \geq D_k$$

where β_i = heating value per unit of raw coal from origin i,

γ_i = heating value per unit of clean coal from origin i, and

D_k = exogenously determined consumption at user k.

Each user was required to meet an aggregate limit on sulfur dioxide emissions. However, each user could blend coal from 2 or more origins to meet its sulfur dioxide emission standard.

(5) $\sum_{i}\sum_{m}\phi_i U_{ikm} + \sum_{i}\sum_{j}\sum_{m}\theta_i V_{ijkm} \leq S_k = \pi_k D_k$

where ϕ_i = units of sulfur dioxide contained in one unit of raw coal from origin i, θ_i = units of sulfur dioxide contained in one unit of clean coal from origin i, S_k = maximum allowable sulfur dioxide emissions at user k, and π_k = maximum allowable emission standard for user k measured as units of sulfur dioxide per unit of heating value. Additional nonnegativity and integer restrictions were:

(6) $M_i, U_{ikm}, V_{ijkm}, \geq 0$; $Y_j = 0$ or $Y_j = 1$; and, $X_k = 0$ or $X_k = 1$.

Data

Data on 1975 and projected 1980 coal consumption in Iowa were obtained from electric generating utilities and industrial firms using coal-fired boilers. Nearly 131 trillion Btu's from coal were consumed in 1975. The projected 1980 coal consumption is 299 trillion Btu's. Sulfur dioxide emission standards applicable to each coal user location were obtained from federal, state and county agencies with pollution control authority (Linn County, 1975, Polk County Board of Health, 1972, State of Iowa, 1976, and U.S. Environmental Protection Agency, 1971).

Data on the sources of coal consumed in Iowa in 1976 and discussions with an advisory committee of executives from electric utility companies and coal brokerage firms were the basis for selecting out-of-state coal supply origins to be included in this study. The seven out-of-state origins include Gillette and Sheridan, Wyoming; Sparta, Canton, and West Harrisburg, Illinois; Nortonville, Kentucky; and Unionville, Missouri.

FOB coal prices and sulfur and Btu content for coal from these out-of-state origins were obtained from bonded coal bids submitted by coal brokers to electric generating plants from mid-1976 to early-1977 and from discussions with the advisory committee.

Price and quality data for 2 underground mines and for 5 strip mines currently operating in Iowa were obtained from municipal electric utilities. Based upon the data on these 2 underground and 5 strip mines in Iowa, FOB prices for the 24 potential mine sites were estimated by the following equation (Libbin and Boehlje, 1977 and Nagarvala, Ferrell and Oliver, 1976):

(7) $P = \alpha S^{\beta}$

where P = estimated price, S = sulfur content in percent of weight, α = constant, and β = regression coefficient.

The resulting price-sulfur relationship for Iowa strip mine coal is:

(8) $P = \$21.12S^{-0.29}$, $R^2 = 0.63$.

These 1977 FOB coal prices do not include additional mining costs resulting from The Surface Mining Control and Reclamation Act of 1977 (U.S. Congress, 1977). Estimates of additional mining costs resulting from this act were obtained from executives of coal mining companies. These estimates, added to the estimated 1977 FOB mine prices in Table 1.

Two additional sets of FOB mine coal prices were generated for the 24 potential strip mine sites in Iowa and for Northern Missouri strip mine coal. Both additional sets of prices are based on the assumption held by Iowa coal mine and utility executives, that 1977 FOB Iowa mine prices would not allow for the recovery of the total cost of opening and operating new mines.

The first additional set of FOB strip mine prices presented in Table 3 is based on the estimated average 1977 cost of opening, operating, and reclaiming a new 70,000 ton-per-year mine with an average 50-foot highwall and a 30-inch seam. This cost was estimated to be $17.33 per ton (Baumel, Drinka, and Miller, 1978). The difference between $17.33 and $13.48--the estimated average Iowa 1977 FOB mine price--was added to each estimated price obtained from Equation 8 to approximate the 1977 FOB mine price to open, operate and reclaim a new Iowa strip mine under average mining conditions at each of the 24 potential strip mine sites in Iowa.

The second additional set of FOB strip mine prices presented in Table 3 is based on the estimated cost of opening, operating and reclaiming a new Iowa strip mine under high cost mining conditions. This cost was estimated to be $20.06 per ton (Baumel, Drinka and Miller, 1978). The difference between $20.06 and $13.48 was added to each estimated price obtained from Equation 8 to approximate the 1977 FOB mine price to open, operate and reclaim a new Iowa strip mine under a high-cost mining operation at each of the 24 potential strip mine sites in Iowa.

These two levels of higher FOB prices were also applied to Missouri strip mine coal, because the characteristics of Northern Missouri coal are similar to those of Iowa coal. Because the scale of operations is larger at Missouri mines than at Iowa mines, an estimated $1.00 per ton cost savings was subtracted from the Iowa price adjustments.

Coal beneficiation plant performance data and investment and operating costs were obtained from a "package" beneficiation plant proposed for construction in Iowa and on performance data and costs from the experimental coal beneficiation plant at Iowa State University (Grieve, Chu and Fisher, 1976).

The "package" beneficiation plant would process 840,000 tons of raw coal per year. The beneficiation process is estimated to yield 77 percent clean coal and 23 percent refuse resulting in 646,800 tons of beneficiated coal per year. The process removes about 35 percent of the sulfur and increases the Btu content of the beneficiated coal by about 12 percent (Grieve and Fisher, 1978).

The total investment cost in 1977 dollars is estimated to be $2,588,000 (Eldridge, 1977). At a 10 percent interest rate, the annual interest and capital recovery is estimated to be $326,413. Other fixed annual costs including management, insurance, taxes, etc., are estimated to be $350,444 per year. The variable cost of operating the plant is estimated to be $0.819 per ton (Eldridge, 1977).

The 23 percent refuse from the beneficiation process must be returned to the mines for disposal. To minimize the distances that refuse must be hauled to the mines, the 8 potential beneficiation sites were restricted to the 3½-county producing area. It was assumed that each site located on rail lines would need 5,800 feet of rail siding. The potential sites currently have from 0 to 3,360 feet of rail siding. The annualized cost of the additional siding was added to the annual investment cost at each location.

Two sets of rail rates were used in the analysis. The first set includes the actual rates on which coal moved from each out-of-state origin selected in this study to each Iowa coal user during the period from January 7 to November 30, 1977. The rail rates in effect during this period of time are referred to as the Ex Parte 336 rate level and were primarily for single-car rail shipments. Only a few coal users had access to multiple-car or unit-train shipments from the selected coal origins during this period.

The second set of rates--referred to as estimated multiple-car rates--includes all the Ex Parte 336 rates as well as estimated 15-car, 50-car and 100-car rates for users who did not have access to these shipment sizes in 1977. The estimated 15-car, 50-car, and 100-car rates were obtained from a computer program designed to estimate variable rail costs. These estimated variable costs were converted to estimated rates by multiplying the estimated variable cost by a ratio consisting of published Ex Parte 336 rates for the same size shipments to different destinations divided by the estimated variable costs to those destinations.

Trucks perform three coal-hauling functions in this analysis. First, coal is hauled from strip mines to coal beneficiation plants in tandem-axle dump trucks. Second, coal beneficiation refuse is hauled for disposal from beneficiation plants to mines in tandem-axle trucks. Third, trucks compete with rail and barge in hauling beneficiated coal to utility and industrial users. Tandem-axle dump trucks pulling pup trailers currently haul most of the coal from Iowa mines to coal users. The costs of hauling coal for each of these movements was estimated using mid-1977 cost levels (Eldridge, 1977). The cost function for hauling coal from the mines to beneficiation plants and for hauling refuse from the plants to the mines was $C_t = \$0.1743 + \$0.0578\ m$ where C_t = cost per ton and m = loaded miles. Refuse was not permitted to be a backhaul because of the difficulty of cleaning the refuse sludge from the truck after each load. The cost functions for hauling coal from the mine to users or from the beneficiation plant to users are:

Loaded Miles	Cost Function
0 - 20	$C_t = \$0.3668 + \$0.0414\ m$
20.1 - 75	$C_t = 0.3711 + 0.0411\ m$
75.1 - 200	$C_t = 0.7439 + 0.0360\ m$

Assuming a 15 percent profit margin, trucking rate functions were estimated from the trucking cost estimates by multiplying each trucking cost function by 1.15.

Data on the cost of combined rail-barge movements from Sparta and West Harrisburg, Illinois and from Nortonville, Kentucky to Iowa destinations on the Mississippi River were obtained from coal mining and barge companies.

Data on the 1977 rail receiving capacity were obtained from each utility and industrial user. Estimates were made of the cost of upgrading the rail receiving capacity of each coal user to the next larger size of shipment. If the facility could receive 100-car unit trains, no additional investment in rail receiving capacity was permitted. If the projected number of tons of coal to be used in 1980 would provide less than one shipment per month at the next size shipment, or if the user historically received all of its coal by truck or barge, the user was not given the opportunity to increase its rail receiving capacity. The variable costs of receiving, unloading and transferring the coal to a live storage area by mode and size of shipment were obtained from utility company executives.

Findings.

Five computer solutions are presented in Table 2. Under Ex Parte 336 rail rates, the amount of raw strip mine coal produced in Iowa in 1980 would vary from a high 3,290,000 tons at 1977 FOB mine prices to 600,000 tons at a price of $20.06 per ton FOB Iowa strip mine price. The number of coal beneficiation plants would vary from one to five depending on the FOB strip mine coal price and the type of rail rates. The analysis of coal mining costs suggests that the most realistic average FOB Iowa strip mine coal price is $17.33 per ton. Solutions I and II are based on this price.

The estimated tons of coal consumed in Iowa in 1980 by coal origin under Solution I and II are presented in Table 3. Under Solution I, nearly 60 percent of the coal would be supplied from Wyoming, up from about 40 percent of Iowa's 1976 coal consumption; Illinois would supply 30 percent, down from about 36 percent in 1976 (U.S. Department of the Interior, 1976). The remainder--about 1.6 million tons--would come from Iowa sources. Under Solution I, slightly over 300,000 tons would move directly from underground Iowa mines to users. Two beneficiation plants would require 1,680,000 tons of raw strip mine coal to produce 1,293,600 tons of cleaned coal. In 1975, total Iowa strip mine coal production was only 259,000 tons (U.S. Department of the Interior, 1977). Thus, under the assumptions of this solution, strip mine coal production would increase about 550 percent over 1975 production.

Solution	Iowa strip mine Price per ton	Rail rates	Tons of raw Iowa strip mine coal produced[a]	Number of coal beneficiation Plants	Estimated total cost of 1980 coal consumption
I	$17.33	Ex Parte 336	1,680,000	2	$335,675,000
II	$17.33	Estimated multiple-car	840,000	1	328,000,000
III	$20.06	Ex Parte 336	600,000	1	338,830,000
IV	$20.06	Estimated multiple-car	0	0	329,725,000
V[b]	1977 FOB Mine Prices	Ex Parte 336	3,290,000	5	329,475,000

[a] Iowa Underground mines produce 307,290 tons of coal in all solutions.

[b] Source: (Eldridge, 1977)

Table 2. Summary of five computer solutions.

Source of coal	Solution I		Solution II	
	Tons of coal	Percentage of total	Tons of coal	Percentage of total
Wyoming	9,477,160	59.4	11,096,220	67.4
Illinois	4,856,980	30.5	4,419,560	26.8
Kentucky	0	0	0	0
Missouri	21,000	0.1	0	0
Iowa				
Underground mine	307,290	1.9	307,290	1.9
Beneficiated strip mine	1,293,600[a]	8.1	646,800[b]	3.9
Total	15,956,030	100.0	16,469,870	100.0

[a] 1,680,000 tons of raw coal are required to yield 1,293,600 tons of beneficiated coal.

[b] 840,000 tons of raw coal are required to yield 646,800 tons of beneficiated coal.

Table 3. Estimated quantitites of coal consumed in Iowa by source of coal under solutions I and II, 1980.

Given that Iowa coal production has continued to decline during a period of increased coal consumption, and given the assertion of electric utility and mining executives that raw Iowa strip mine coal consumption will continue to decline, one can conclude that the estimated 550 percent increase in Iowa strip mine coal production under Solution I over 1975 production levels can be attributed to coal beneficiation plants.

Solution II is based on the assumption that multiple-car rates will be available for both Iowa and out-of-state coal by 1980 to all but 13 Iowa coal users. The multiple-car rates were not made available to these 13 users because of relatively low projected 1980 coal consumption, or because the coal user has historically received coal only by barge. Therefore, Solutions I and II provide an evaluation of the impact of improved transportation on the production and marketability of Iowa coal.

Wyoming would supply 67 percent of the 1980 coal consumed in Iowa under Solution II; this compares with almost 60 percent under Solution I and 40 percent in 1976. Illinois would supply about 27 percent in Solution II compared with 30 percent in Solution I and 36 percent in 1976. No coal would be received from either Kentucky or Missouri. Iowa mines would supply nearly 6 percent of total coal consumption under Solution II compared with 10 percent under Solution I. This comparison shows that the introduction of multiple-car rail rates would increase the amount of Wyoming coal consumed in Iowa and at the same time decrease the consumption of Missouri and Iowa coal. The reason for the large reduction of Iowa strip mine production under the multiple-car rate solution is that the estimated multiple-car rate reductions from single-car rates are much greater for Wyoming and Illinois coal than the estimated rate reductions for the short hauls from Iowa coal beneficiation plants to Iowa users. The estimated rate reductions for 50-car trains from single-car shipments from Wyoming and Illinois range up to \$6.13 and \$4.34 per ton, respectively, but only up to \$2.46 per ton from Iowa (Baumel, Drinka and Miller, 1978). Most of the Iowa rate reductions are less than \$1.50 per ton.

The amount of coal consumed by sulfur emission standard under Solution I is shown in Table 4. All underground Iowa coal would be consumed by boilers with the 8-pounds of SO_2 per million Btu emission standard. About 50 percent of the beneficiated coal would be consumed by boilers with the 8-pound standard; about 11 percent would be consumed by users with the 6-pound standard, and about 39 percent by users with the 5-pound standard. Boilers with the 1.2-pound emission standard would consume Wyoming coal exclusively.

Table 5 shows the amount of Iowa and out-of-state coal shipped by mode under Solutions I and II. Under Solution I, nearly 89 percent of Iowa coal would be transported by truck and 11 percent by rail; in 1976, 89 percent of the Iowa coal shipments were transported by truck (U.S. Dept. of the Interior, 1977). Under Solution I, more than 62 percent of the out-of-state coal consumed in Iowa would be shipped by unit trains, 14 percent by rail-barge, and less than 1 percent by truck. Under Solution II almost 32 percent of the Iowa coal would be shipped in 15-car shipments, and 14 percent would move in single-car rail shipments.

Assumed maximum SO_2 emission standard in pounds per million Btu	Iowa coal				Out-of-state coal	
	Beneficiated		Underground			
	Tons	Percentage	Tons	Percentage	Tons	Percentage
1.2	0	0.0	0	0.0	9,219,050	64.2
5	498,710	38.6	0	0.0	953,220	6.6
6	148,090	11.4	0	0.0	3,626,350	25.3
8	646,800	50.0	307,290	100.0	556,520	3.9
Total	1,293,600	100.0	307,290	100.0	14,355,140	100.0

Table 4. Estimated coal consumption by Iowa users by SO_2 emission standard and coal origin under solution I, 1980.

Mode of transport	Solution I		Solution II	
	Iowa coal	Out-of-state coal	Iowa coal	Out-of-state coal
Truck	1,419,490	21,000	519,730	0
Rail				
Single-car	181,400	3,340,730	133,280	57,950
15-car	0	0	301,080	1,920,500
50-car	0	376,540	0	2,543,920
100-car	0	8,545,580	0	8,922,120
Barge	0	2,071,290	0	2,071,290
Total	1,600,890	14,355,140	954,090	15,515,780

Table 5. Estimated amount of coal transported to Iowa users by mode and coal origin under solutions I and II, 1980, in tons.

The introduction of multiple-car rail rates would shift some Iowa coal from truck to rail. The greatest impact, however, would be to increase the amount of Wyoming coal consumed in Iowa and to reduce the amount of coal consumed from all other sources.

Most of the coal trucked from Iowa strip mines to beneficiation plants would come from mines within 10 miles of the plant. The maximum distance that coal would be trucked from a mine to a cleaning plant in this solution is about 25 miles.

The estimated total cost (Table 2) of the delivered 1980 projected coal consumption is $335,675,000 under Solution I. The estimated total cost would fall to approximately $328,000,000 under Solution II. Thus, while the multiple-car rates would reduce the Iowa coal share of total 1980 coal consumption, the multiple-car rates would reduce the total cost of this consumption by about $7,675,000.

If Iowa and Missouri coal prices were to increase to an average of about $20 per ton, the level of Iowa high sulfur strip mine production would decline to 600,000 tons at the Ex Parte 336 rate level and to zero tons under the multiple-car rates (Table 2). At these FOB mine prices, the total delivered cost of the coal consumed in Iowa would decline $9.1 million per year under the multiple-car rates compared to the Ex Parte 336 rate levels.

Conclusions

1. Coal beneficiation plants would reverse the downward trend in the production of Iowa strip mine coal except when very high FOB Iowa coal prices are combined with multiple-car rail

rates for most Iowa coal users. The estimated amount of strip mine Iowa coal to be produced in 1980 would vary between 0 and 3,290,000 tons depending upon the assumed level of FOB Iowa mine coal prices, and the level of rail rates.

2. The analysis of Iowa coal mining costs ($17.33 per ton for typical mining operations) suggests that the most likely range of 1980 raw strip mine coal production in Iowa--assuming Ex Parte 336 rail rates--would be about 1,680,000 tons of coal per year by 1980. This would make Iowa strip mine coal production about 550 percent greater in 1980 than in 1975. This level of strip mine coal production would require two coal beneficiation plants.

3. The largest market for beneficiated Iowa coal is at coal users with the 8-pound per million Btu SO_2 emission standard. However, up to about 50 percent of the cleaned coal would be consumed by users with 5- and 6-pound SO_2 emission standards.

4. Almost all the Iowa coal would be transported to the central and east-central Iowa coal users by truck. Typically, trucks have a cost advantage over single-car rail rates up to approximately 140 miles. Beyond that point, single-car rail rates are cheaper than estimated truck rates.

5. Reduced transportation rates on multiple-car rail shipments would reduce, rather than increase, Iowa coal production. The amount of strip mine coal produced in Iowa in 1980 would vary from zero tons to 840,000 tons under the estimated multiple-car rates solutions, depending upon the assumed level of Iowa coal prices. The reason for the reduction of Iowa strip mine production under the estimated multiple-car rates is that the estimated Wyoming

and Illinois multiple-car rate reductions are much larger than the rate reductions for the short hauls from Iowa coal beneficiation plants to Iowa users.

6. The estimated multiple-car rates would reduce the total cost of supplying the 1980 coal requirements in Iowa by $7.7 to $9.1 million depending upon the assumed level of Iowa coal prices. This creates the following policy dilemma: Should lower-cost multiple-car and unit-train rail rates from out-of-state coal origins be discouraged to increase Iowa coal production, or should multiple-car and unit-train rail rates be encouraged to reduce the total cost of supplying Iowa's coal requirements?

7. Coal beneficiation plants would increase the marketability of Iowa strip mine coal beyond the 1976 production level under all solutions except the multiple-car rate solution with an average Iowa FOB strip mine price of $20.06. If the Iowa coal industry can produce strip mine coal for around $17.33 per ton, and if coal users do not begin to jointly obtain large volumes of Wyoming coal at low FOB prices shipped in unit trains, up to two coal beneficiation plants would significantly increase the marketability of Iowa strip mine coal.

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AN EVALUATION OF THE DESULFURIZATION POTENTIAL OF U.S. COALS

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ABSTRACT

We have derived a generalized approach to the evaluation of the desulfurization potential of coals. It is applied here to various cleaning processes for the coal reserves in each of the six major coal-producing regions in the U.S. and for the coal reserve base for the U.S. as a whole. The methodology characterizes the entire U.S. reserve base via 36,000 composite coal analyses showing total weight, percent ash, percent sulfur, and Btu content. In addition, each reserve record is associated with one float-sink analysis as reported in RI 8118. The mathematical approach adopted allows the characteristics of the cleaned coal to be obtained from those of the raw coal by scaling the raw coal characteristics by factors dependent on the cleaning process involved and the washability analysis of the raw coal. By reducing all cleaning processes to this same general form of multiplying factors, the data manipulation for all the cleaning processes under consideration can be carried out simultaneously, thereby substantially reducing computer costs. The approach is valid for general cleaning processes and is independent of the specific performance measures to be used for the processes.

1.0 INTRODUCTION

The purpose of the work described in this paper was to develop a computer based methodology for the evaluation of the desulfurization potential of U.S. coal reserves. The technique used had to allow for the subclassification of coal reserves by type, deep or strip, and by geographic subarea, region or state. The types of desulfurization processes to be considered included single and multi-stream physical cleaning, chemical cleaning, and combined physical and chemical cleaning. The actual evaluation involved measuring values such as the following:

- The weight and Btu recovery percents which could be achieved as a function of the required level of lbs of SO_2/MM Btu.
- The actual tons of coal or Btus which could be obtained as a function of the required level of lbs of SO_2/MM Btu.
- The percent weights and Btus available versus the level of flue gas desulfurization required to meet some proposed removal NSPS.
- The actual tons of coal or Btus which could be obtained as a function of the level of the percent removal standard to be required.

Finally, the technique selected was to take into account the large variability associated with the characteristics of different coals.

The large number of coal reserve resources and the large number of sample analyses associated with each resource that had to be processed in order to take variability into account introduced into the problem the difficulties associated with large-scale data handling. In particular, computer costs tend to escalate rapidly when large amounts of data processing have to be done. An additional constraint here was that the final computer programs produced were to be easily transferable from computer to computer; thus, the data processing techniques used had to be restricted to those very simple ones which are universally available.

The method used for computing the desulfurization potential of the reserve base meets all of the above criteria. It significantly reduces the computational effort required by other approaches. It also has the additional advantage that much of the actual computation performed is independent of the specific performance measures to be used for the evaluation. Thus, multiple performance measures can be computed without repeating the entire calculation. In essence, the approach taken allows the composition of coal cleaned by a variety of cleaning processes to be computed directly from the composition of the raw coal simply by scaling by appropriate factors which are dependent on the washability analysis of the coal and the specifications of the cleaning processes. These scale factors, whose computation can be lengthy, need be computed only once for each cleaning process and washability analysis pair. Once calculated, however, each factor is used many times via a simple multiplication for every sample analysis corresponding to the same reserve resource and for every reserve corresponding to the same washability analysis. This effects considerable saving in the computing time required.

2.0 OVERLAYING THE DATA

The data available for the evaluation was as follows:

- 587 sets of washability analyses for coal from sample mines in the U.S. as reported in Cavallaro, Johnston, and Deurbrouck (1976)--i.e. RI8118.
- The reserve base of U.S. coal, consisting of 3167 records specifying the weight of the resource for both strip and underground coal, together with the maximum, minimum, and mean levels of the major constituents of the coal in that resource. This data is consistent with that summarized in Thomson and York (1975) and Hamilton, White and Matson (1975)--i.e. IC8680 and IC8693.
- Approximately 50,000 detailed sample coal analyses taken from the coal data base of the U.S. Bureau of Mines in Denver, Colorado. This data includes the composition of each sample in terms of its ash, sulfur, and heat content.

Given these three sets of data as a starting point, the first step in the analysis was to overlay them into a single data base which contained 36,000 coal resource records and which had the following information for each:

- The location in terms of its region, state, county, and bed
- The weight in tons of both strip and underground coal
- The mean percent by weight of ash, organic sulfur, and pyritic sulfur

- The mean heat content expressed in Btu/lb
- The float-sink distribution of the coal characteristics

The coal reserve resources and the washability data of RI8118 are each specified by state, bed and county; however there is not an exact correspondence between reserves and washability data since for many of the reserves there are no washability data. In order to be able to determine the desulfurization by physical cleaning processes of coal resources having no washability data, the reserve resources were assigned washability data in the following manner:

1. If one or more state, bed and county matches are found between a given reserve and the washability data, the reserve is assigned that washability data which has coal composition closest (in the least squares sense) to the composition of the reserve. If no composition data is given for that reserve resource, the resource is subdivided into as many parts as there are matching washability data and each is assigned one of the washability analyses.
2. If there are no state, bed and county matches between a given reserve resource and the washability data, look for state, bed and region matches. Assign the reserve the matching washability data as in 1.
3. If no matches occur in either 1 or 2, look for state and county matches. Assign the reserve the matching washability data as in 1.

4. If no matches occur in 1, 2, or 3 assign the reserve the washability data from other beds in the same state and region as in 1.

5. For some states there are no washability analyses at all; reserve resources in those states are assigned washability data from other states in the same region as follows:

   North Carolina is assigned washability data from Virginia
   Michigan is assigned washability data from all states in the Eastern Midwest region
   Texas is assigned washability data from Oklahoma
   South Dakota is assigned washability data from North Dakota
   Idaho
   Oregon } are assigned washability data from
   Washington } Montana and Wyoming

   The washability data of the relevant state or states is assigned to the resource as in 1.

Thus all the coal reserve resources were assigned washability data.

The analytical data file consists of approximately 50,000 records each of which gives coal composition data for a reserve resource sample. This sample analysis data was overlaid with the reserve base to obtain coal composition data for each reserve resource. Each resource has several sample analyses corresponding to it and, in the absence of any method of assigning weights to the different analyses for the same resource, all were weighted equally. The variation in the samples for a given resource was taken into account by dividing all the coal in that reserve resource into as many parts as there are corresponding sample analyses and each part was assigned the composition of one of the samples. For those reserves that have composition data given on the reserves file and on the analysis file it was assumed that the mean of all the sample analyses should be equal to the composition data given on the reserves tape; if necessary the sample analysis data was scaled to make this so. Reserves having no composition data given on the reserves file were assigned the coal composition given by the RI8118 washability data. Reserves having composition data given on the reserves file but no sample analysis used the coal composition given on the reserves file.

By overlaying the coal reserves file and the analysis file in this manner an expanded reserves file of approximately 36,000 records was obtained, each record consisting of resource identification (by state, bed and county), weight of coal for both strip and underground, and the composition of the coal. 36,000 records are obtained and not 50,000 as on the original analysis file because a number of the sample analyses either do not correspond to any of the reserve resources or correspond to a given resource which shows no coal available in both strip and underground reserve. For a given state, bed and county group there will be several records on the file each having the same weight of reserves (such that the total adds up to the actual weight in the resource) but having possibly different composition data corresponding to the different sample analyses for that resource. The sulfur content of the coal is given in the coal reserves file and in the analysis file only as total sulfur content; this was divided into pyritic and organic sulfur in the ratio in which these two occur in the washability data that corresponds to that resource.

The extensive data manipulation that is necessary to obtain the overlayed reserves and analytical file is independent of the cleaning process to be considered and is dependent only on the original three data bases of coal washability, reserves and sample analyses. The overlaid file has therefore been created only once but has been used in many subsequent analyses.

3.0 IMPLEMENTING THE CLEANING PROCESSES

To implement the effect of the cleaning processes on the reserve resources, use has been made of the fact that a single washability analysis corresponds to many records on the overlaid reserves data file. By doing so the computational time required to perform this part of the analysis has been reduced by a factor of approximately sixty. The methodology developed can treat any cleaning process that is of one of the following specific types.

1. A physical cleaning process.
2. A chemical cleaning process that removes specified percentages of the characteristics of the raw coal (ash, pyritic sulfur, organic sulfur).
3. A chemical cleaning process that reduces the levels of the characteristics to given threshold values.
4. Combinations of 1 and 3 or combinations of 2 and 3.
5. A blend of the product coal from two of the above processes.

6. One of processes 1-4 on the coal product of another of processes 1-4.

Reductions in the weight and Btu/lb of the coal by given percentages can be specified directly for processes of types 2 and 3 and for processes of type 1 as operating penalties over and above the reductions caused by the physical separation process. Physical cleaning processes are restricted by the RI8118 washability data to size fractions of 1-1/2 inches, 3/8 inch or 14 Mesh, and to specific gravity fractions of Float -1.3, 1.3-1.4, 1.4-1.6 or the sink from 1.6.

A physical cleaning process can be completely specified by the size fraction to which the coal is crushed before separation plus the following quantities for each of the four specific gravity fractions:

- The percent ash removed from the specific gravity fraction.
- The percent pyritic sulfur removed.
- The percent organic sulfur removed.
- The percent Btu/lb recovery for the specific gravity fraction.
- The percent weight recovery (=0.0 if this specific gravity fraction is discarded).

These quantities are in addition to the amount of each characteristic that is removed by the physical separation process. A cleaning process of type 2 can be expressed in terms of the above five quantities alone. A cleaning process of type 3 can be expressed in terms of the above quantities together with threshold values for those characteristics that are reduced to threshold levels.

Given such a specification of a cleaning process of type 1 or 2 and the file of the RI8118 washability data, it is possible to construct an array T(i,j,k) which fully characterizes the cleaning of coal from a particular state, bed and county group by the cleaning process. Here i corresponds to the index of the washability data (determined from the state, bed and county group), j corresponds to the cleaning process under consideration, and k corresponds to the characteristics of the coal that are subject to change by cleaning (weight, ash, pyritic sulfur, organic sulfur, and Btu/lb). On cleaning by process j a sample of raw coal having state, bed and county group corresponding to washability index i and characteristics R(k), one obtains cleaned coal having characteristics

$$C(k)=R(k). \quad T(i,j,k).$$

Thus the effect of a cleaning process on coal of a given washability is obtained simply by scaling the characteristics of the coal by the relevant factors from the T array. Chemical cleaning which reduces characteristics to threshold values (type 3 processes) can be simulated by reducing the relevant characteristics after scaling by the T factors.

The array T(i,j,k) is computed as follows. For a type 2 cleaning process j the specification of the process described above completely determines the T matrix. The process specification gives the proportion D(k) of characteristic k of the feed coal that appears in the cleaned coal. If

k=1	corresponds to weight
k=2	corresponds to ash content
k=3	corresponds to pyritic sulfur content
k=4	corresponds to organic sulfur content
k=5	corresponds to Btu/lb for the coal

then

$$T(i,j,1)=D(1)$$

$$T(i,j,k)=D(k)/D(1), \qquad k=2,3,4,5.$$

This is independent of the washability index i.

For a type 1 process the proportion $P(\ell,k)$ of the feed coal in specific gravity fraction ℓ and having characteristic k that appears in the cleaned coal is given by the washability data for the feed coal. Any additional reduction in the levels of the characteristics is given by the process specification and can be expressed as $D(\ell,k)$. Combining these two, the proportion of the feed coal appearing in the product is

$$\sum_{\ell} P(\ell,k) . \ D(\ell,k)$$

where the summation is over the four specific gravity fractions of the RI8118 washability data. Then

$$T(i,j,1)=\sum_{\ell} P(\ell,1) . \ D(\ell,1)$$

and

$$T(i,j,k)=\sum_{\ell} P(\ell,k) . \ D(\ell,k)/T(i,j,1), \qquad k=2,3,4,5.$$

Having constructed this T matrix from the specifications of the cleaning processes and the washability data, it is combined with the overlaid reserves and analytical data file. The characteristics of the raw coal from each of the 36,000 reserve resource records on the file are scaled by the appropriate factors from the T matrix to obtain the characteristics of that coal after cleaning by each of the processes. Any reduction in characteristic values to threshold values for a type 3 process is done at this stage.

A new file is created consisting of 36,000 records as before but now each record contains not just the reserve levels and characteristics of the raw coal but those values also for the processed coal for each cleaning process. This file is then used to assess the desulfurization potential of the coal reserves.

4.0 AN EXAMPLE APPLICATION

As an example application of this methodology, Figures 1-3 show for Northern Appalachian coal, Eastern Midwest coal and Western coal, the percentage of the total regional resource Btus (from strip and underground coals combined) that by cleaning can be made to meet a given percent sulfur removal New Source Performance Standard. The abscissa of the curves is the New Source Performance Standard, while the ordinate is the percent Btus obtainable. An upper limit to the emissions level of the resultant coal of 1.2 lbs $SO_2/10^6$ Btu was assumed; above this level the processed coal is unacceptable regardless of the percent sulfur removed in the process. A lower limit of 0.5 lbs $SO_2/10^6$ Btu was used; raw coal below this level need not be cleaned at all; if the processed coal lies below this level then the amount of coal that has to be cleaned is just that amount so that the combined raw and cleaned will reach 0.5 lbs SO_2/m Btu. The cleaning processes used here are as follows:

- Physical coal cleaning using 1-1/2 inch mesh at 1.6 specific gravity of separation.
- Physical cleaning using 3/8 inch mesh and separation at 1.3 specific gravity. An operating energy penalty of 1% was assumed in addition to the energy lost directly through the separation process.

- Meyers process: this is a chemical cleaning process with a threshold of 0.2 percent pyritic sulfur. A 5% energy loss was assumed in the process together with an operating penalty of 2% energy loss and a weight loss of 10%.
- Gravichem process: crush coal to 14 mesh topsize and separate at 1.3 specific gravity. Treat the sink with Meyers process as above; combine float and processed sink.
- A process with 95% pyritic sulfur removal and 20% organic sulfur removal with a 10% energy loss and an operating energy penalty of 2% and a weight loss of 15%.

In all three of the regions shown the process that removes 95% of the pyritic sulfur and 20% of the organic sulfur is the most effective. If no percent sulfur removal standard is imposed but simply the 1.2 lbs $SO_2/10^6$ Btu emission standard then using this cleaning process, 35% of the Northern Appalachian coal meets the emission standard, 9% of the Eastern Midwest coal and 75% of the Western coal. In the Eastern Midwest region none of the other processes can clean more than 4% of the coal to meet the emission standard. In the Northern Appalachian region the Meyers chemical cleaning process and the Gravichem combined physical and chemical process clean more of the coal to meet the emission standard than do either of the purely physical cleaning processes. This ordering is reversed for the Western region coal.

Figures 4-6 show, for the same three regions the percentage of the total regional resource Btus (from strip and underground coals combined) that will meet a 90 percent sulfur removal standard if flue gas desulfurization (FGD) at specified levels is applied to the coal cleaned by the above cleaning processes. The abscissa of the curves is the level of FGD that is necessary to meet the NSPS with the cleaned coal. The ordinate gives the percent of Btus obtained. The relative ordering of effectiveness of the cleaning process is the same as in the Figures 1-3 until FGD cleaning at about 82% is applied. At this stage it is the energy lost by the cleaning process that determines their order of effectiveness. Beyond 90% FGD cleaning the percent Btus obtained is simply that obtained by cleaning all of the coal in the region by the given process.

Figure 7 shows the percent weight of coal reserves (both strip and underground) in the entire United States that can be cleaned to meet specified emission standards. The dashed line indicates an emission level of 1.2 lbs $SO_2/10^6$ Btu. It is seen that approximately 41% of the raw coal reserves by weight will meet an emission standard of 1.2 lbs $SO_2/10^6$ Btu without cleaning.

5.0 COMPARING THE RESULTS

The results produced using the techniques described here differ dramatically from those produced by others -- in particular RI8118 and Foster Associates (1977). A value which is easy to obtain from all three sources, and one which reflects the difference very effectively, is that percent of U.S. coal reserves which meet the 1.2 lbs of SO_2/MM Btu emission standard. As can be seen from Figure 7, our approach estimates it at 41%. RI8118 on the other hand in their Figure 16 give an estimate of 12%. Foster Associates (1977) do not give a value explicitly; however, it can be computed directly from their schedule 25 as being equal to 27%. Our results then for this summary value are significantly higher than those produced by others. It should be observed that both of the other sources use parts of the same data that we use; therefore, the differences cannot simply be attributed to differences in the data.

The data used by RI8118 are of course the washability analyses which are used by us as well. RI8118 makes no use, however, of any weight figures associated with the reserves. Western coals are heavily under represented in RI8118 in that only 40 of the 455 samples come from the Western region and yet almost half of the U.S. coal reserves are in that region. If the values for the individual regions as reported by RI8118 are weighted by the tons of reserves in those regions when the overall U.S. average is computed, then the RI8118 results predict a value of 38% for the percentage of U.S. coal reserves which meet the 1.2 standard. This calculation is shown in Table 1. Thus, the bulk of the difference between our results and those of RI8118 can be accounted for by the difference in the weighting assumptions.

The approach taken by Foster Associates (1977) is based on the IC8680-93 reserve data augmented by some additional data on heat content. They estimate the distribution of lbs of SO_2/MM Btu for each state and coal type from the distribution of sulfur for that state and coal and from the appropriate

TABLE 1. U.S. COAL RESERVES WHICH MEET THE 1.2 EMISSION STANDARD AS REPORTED IN RI8118 AND AS WEIGHTED BY LEVEL OF AVAILABLE RESERVES

Region	(1) No. of Samples	(2) % Meeting 1.2 Standard	(3) Samples Meeting 1.2 Standard	MM Tons of Coal	(4) Weight Meeting 1.2 Standard (million tons)	(5) Weighted % Meeting Standard
Northern Appalachian	227	4	9	68,274	2,731	4
Southern Appalachian	35	35	12	34,907	12,217	35
Alabama	10	30	3	2,982	895	30
Eastern Midwest	95	1	1	89,029	890	1
Western Midwest	44	2.5	1	18,992	475	2.5
Western	44	70	30	203,776	142,643	70
Total	455	12	56	417,959	159,851	38

(1) Source RI8118.

(2) Number of samples times percent meeting standard divided by 100.

(3) Source the reserve base of U.S. coals.

(4) Percent meeting standard times MM tons of coal.

(5) MM tons meeting standard divided by MM tons of coal times 100.

average Btu content for that reserve. The particular value for the 1.2 standard is then taken from this derived distribution via interpolation. As the authors, themselves, recognize this estimation of one distribution from another is highly subject to error. They say the following in their conclusions on page 89.

> "Perhaps the most important conclusion to be drawn from this exercise is that there are inherent difficulties in any attempt to manipulate these reserve estimate distributions. Even a slight change in assumptions can yield significantly different and tentative results. As such, it appears that any defensible statements or conclusions with respect to the ability of coal reserves to comply with SO_2 emission regulations must come from a redistribution of the individual coal analyses used in constructing the Bureau of Mines distributions in IC8690 and IC8693."

From the standpoint of this presentation the critical simplification in the Foster Associates approach is that all coal in a given state and of a given type, regardless of its sulfur content, has the same Btu content. This assumption is the primary cause of the lower value reported by them. Btu content and percent sulfur tend to be negatively correlated. Based on the 36,000 samples used in this study, the overall correlation coefficient for the U.S. is -0.39. For a given coal, when the sulfur content goes down, the Btu content tends to go up. For low sulfur coals, the Btu content is generally higher than the mean; therefore, the use of the mean in the calculation of lb SO_2/MM Btu tends to give a high estimate for low sulfur coals.

This point can be seen very clearly in Table 2 which shows four distributions of the total U.S. coal reserve base as classified by percent sulfur and by a compatible classification of lb SO_2/MM Btu. The first two are

TABLE 2. PERCENTAGE DISTRIBUTIONS OF TOTAL U.S. COAL RESERVES CLASSIFIED BY PERCENT SULFUR AND LB SO_2/MM BTU RANGES

% Sulfur range	lb SO_2/ MM Btu range	Foster Associates		Overlay File	
		% Sulfur distribution	SO_2/Btu distribution	% Sulfur distribution	SO_2/Btu distribution
≤ 0.4	≤ 0.75	19.4	6.4	21.4	22.4
0.5–0.6	0.76–1.08	13.0	15.5	15.2	15.8
0.7–0.8	1.09–1.42	11.9	15.6	8.6	7.7
0.9–1.0	1.43–1.75	7.1	9.1	6.6	6.2
1.1–1.4	1.76–2.42	7.2	7.8	7.4	6.4
1.5–1.8	2.43–3.08	4.9	6.8	3.6	5.1
1.9–2.2	3.09–3.75	4.2	5.9	3.4	3.7
2.3–2.6	3.76–4.42	4.2	3.5	3.2	3.7
2.7–3.0	4.43–5.00	3.3	5.0	2.9	2.7
>3.0	>5.00	24.0	24.4	27.8	26.3

taken directly from Foster Associates (1977), while the second two have been calculated from the overlaid reserve file whose construction was described earlier in this paper. The percent of coal meeting the 1.2 standard can be taken directly from the SO_2/Btu distributions by summing the first two values plus one-third of the third value.

$$6.4 + 15.5 + (15.6/3) = 27.1$$

$$22.4 + 15.8 + (7.7/3) = 40.8$$

Note that the overlay file SO_2/Btu distribution is not calculated from the overlay sulfur distribution; but rather, it is calculated by redistributing the values for lb SO_2/MM Btu for the individual coal analyses as suggested by the quote given earlier.

Now the two sulfur distributions are very similar. This is as expected since ultimately the same data source was used for each. The SO_2/Btu distributions are quite different, however, especially in the lower sulfur ranges. This underestimation in the Foster Associates distribution of material in the lower ranges is predictable from the negative correlation between sulfur content and Btu content. Notice that from the overlay file analysis the two distributions are quite similar. If one assumed that the Foster Associates sulfur distribution was a good measure of the SO_2/Btu distribution, then the Foster Associates data would predict that 36 percent of U.S. coal reserves meet the 1.2 standard. This calculation is as follows.

$$19.4 + 13.0 + (11.9/3) = 36.3$$

This value is much closer to ours.

In conclusion, it does appear that our estimate of 41 percent of the

U.S. reserves meeting a standard of 1.2 lbs SO_2/MM Btu is the best one to date for this quantity based on the data currently available.

6.0 CONCLUSION

In conclusion, we have developed a methodology for the assessment of the desulfurization potential of the entire U.S. coal reserve base. It is independent of the specific assessment criterion used so that assessments may be made using a variety of criteria without it being necessary to repeat much of the computations. As described here the coal reserves are reported on a regional basis; it is a relatively simply procedure to adapt the programs to consider the coal reserves on a state by state basis and this work is currently in progress. The reliability of the results produced using this methodology depends entirely on the reliability of the representation of the coal reserves by the analysis data and the washability data. Since there are several analysis records for each reserve resource the variability of the coal composition within a given resource is likely to be fairly well represented. However the distribution of the sulfur content of the coal into organic and pyritic sulfur was taken from the washability analyses and is therefore much more subject to error. Thus the reliability of the results depends largely on the representation of the reserve resources by the very limited number of washability analyses that are available. Work is currently being undertaken to estimate the effect that variation in the washability data might have on the desulfurization potential of the reserve base.

7.0 CONVERSIONS TO SI UNITS

Ton	907.18 kilograms
Btu	1054.35 joules
$lb/10^6$ Btu	430 nanograms/joule
Inch	0.0254 meters

8.0 REFERENCES

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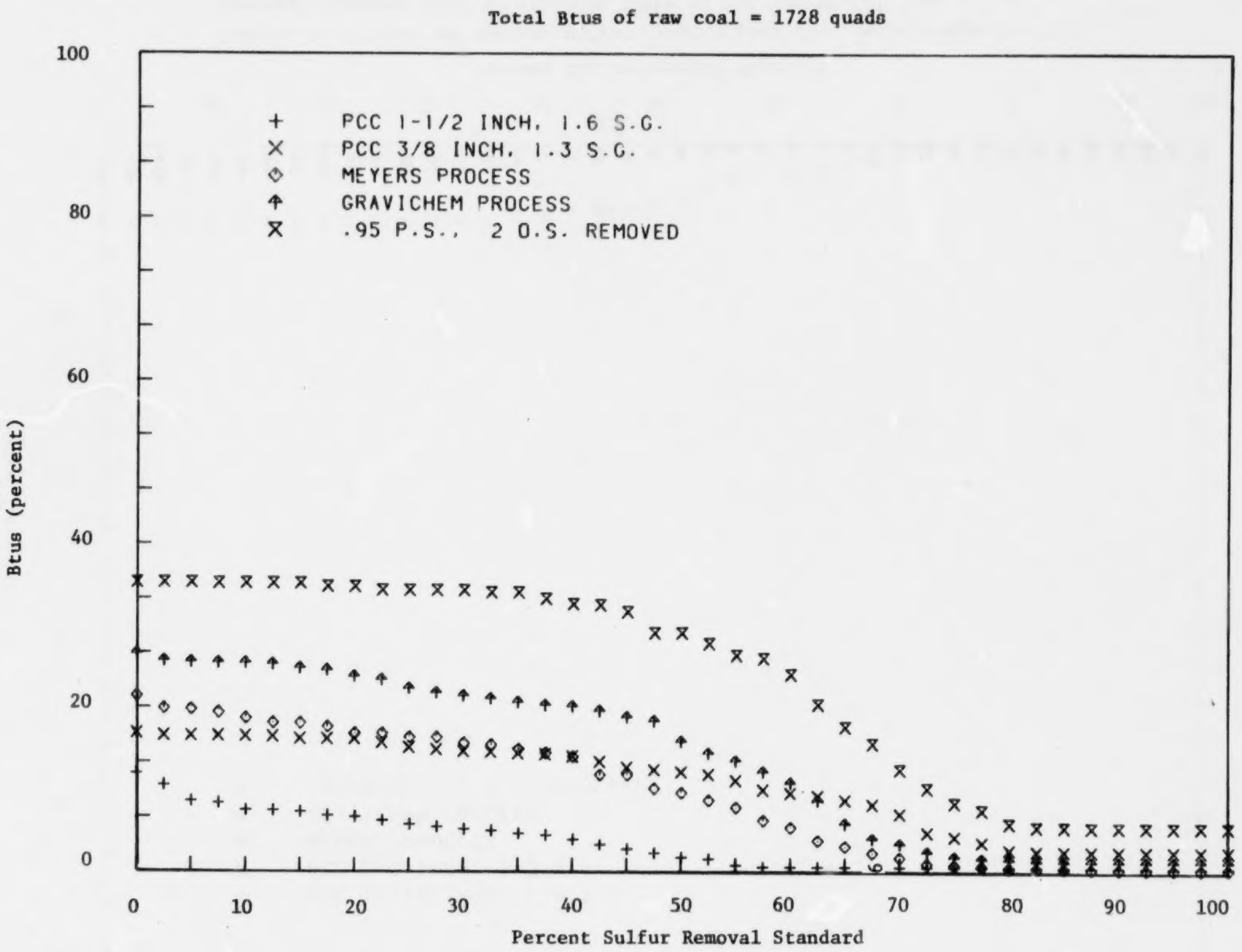

Figure 1. Percent of Northern Appalachian coal that meets percent sulfur removal standards with an emission limit of 1.2 lbs $SO_2/10^6$ Btu.

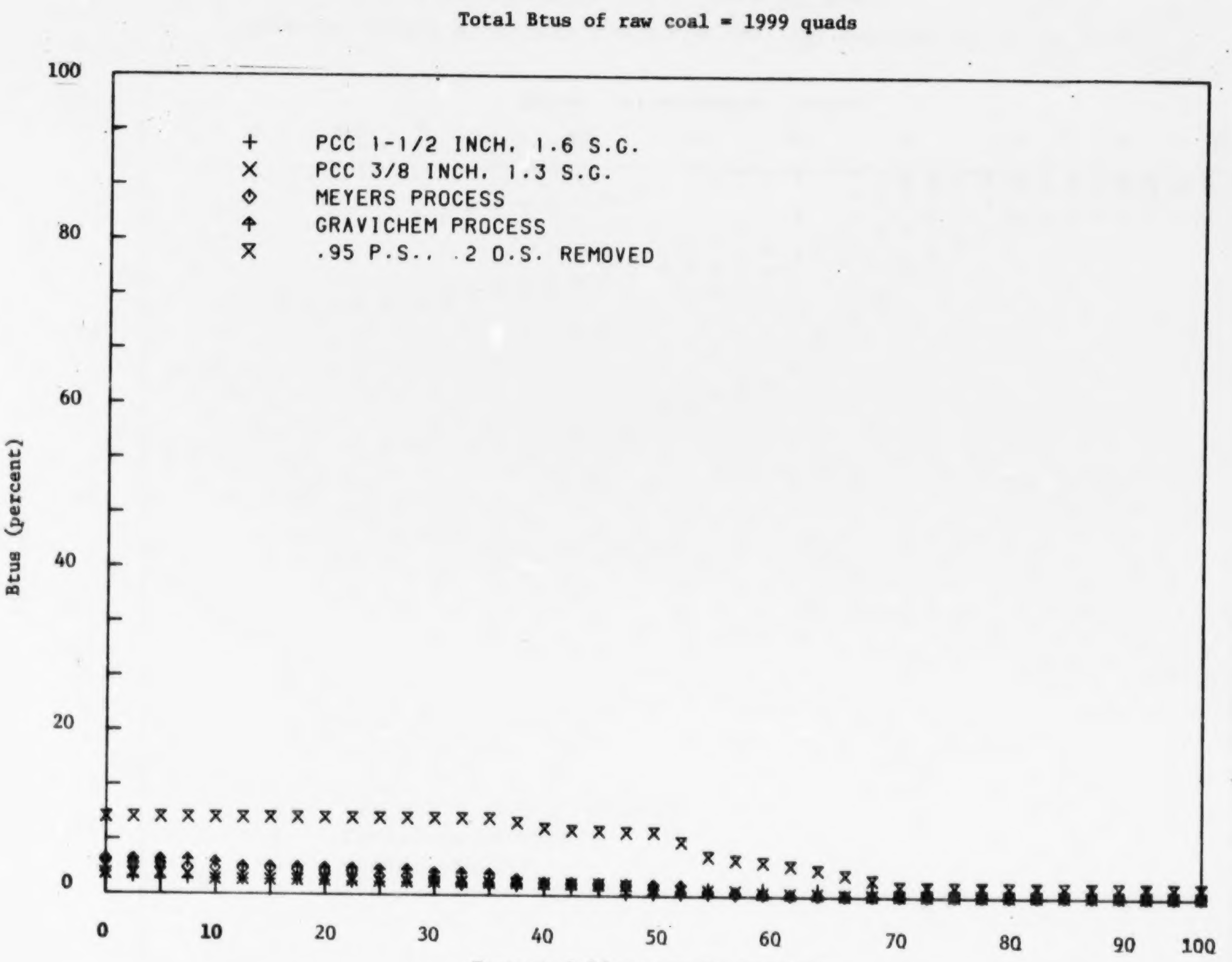

Figure 2. Percent of Eastern Midwest Region coal that meets percent sulfur removal standards with an emission limit of 1.2 lbs $SO_2/10^6$ Btu.

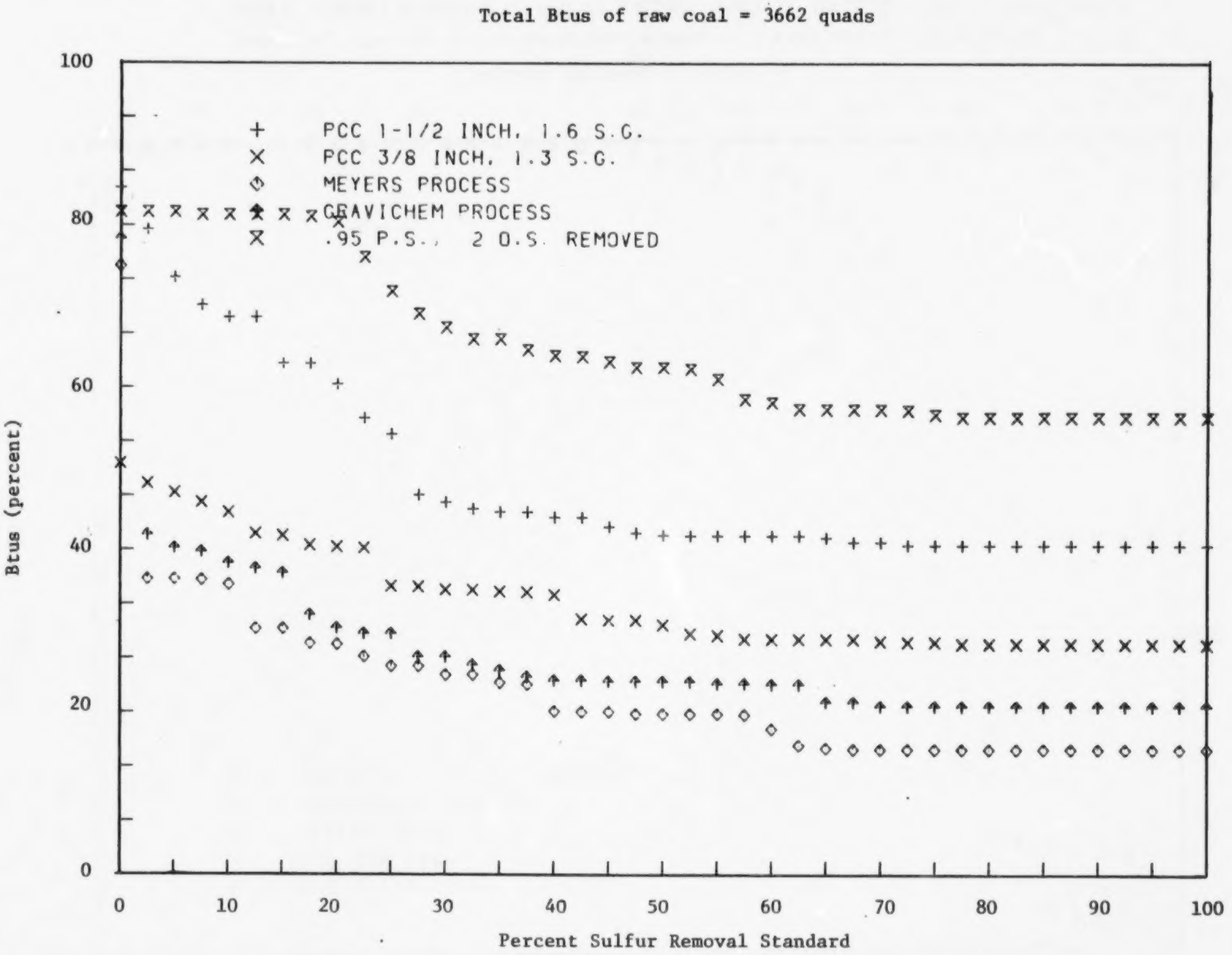

Figure 3. Percent of Western region coal that meets percent sulfur removal standards with an emission limit of 1.2 lbs $SO_2/10^6$ Btu.

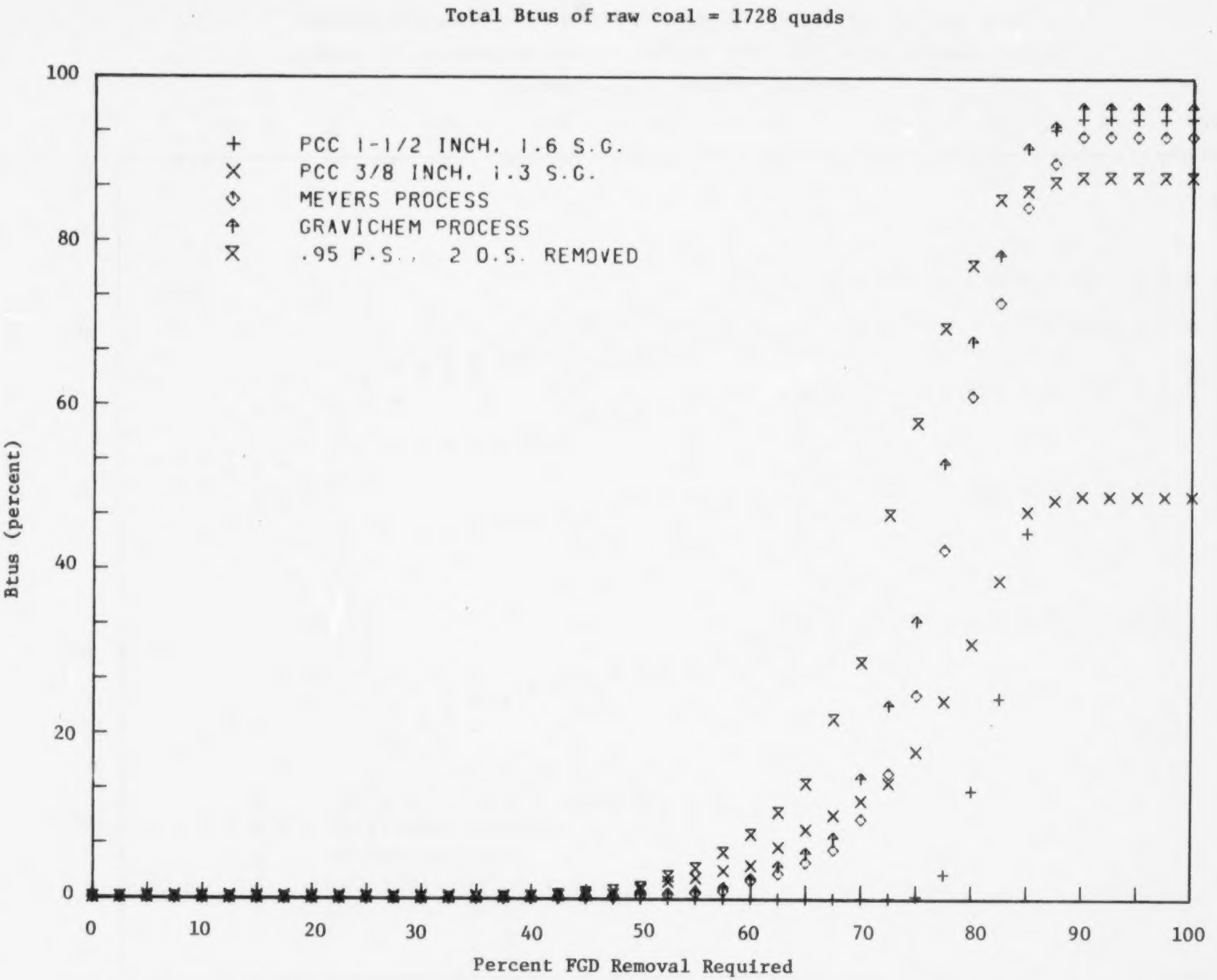

Figure 4. Percent of Northern Appalachian coal that meets a 90 percent sulfur removal standard if FGD at a given level is applied to the cleaned coal.

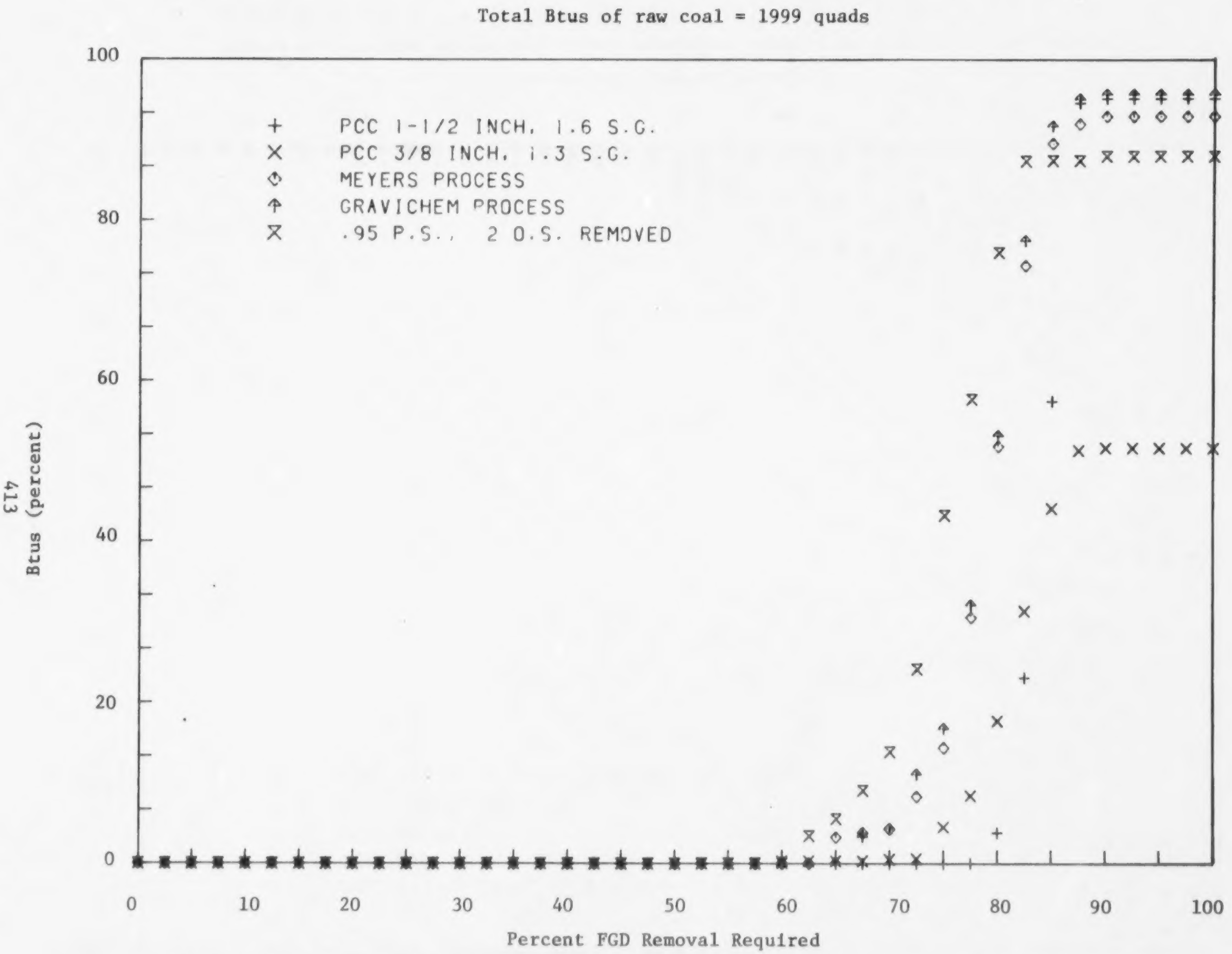

Figure 5. Percent of Eastern Midwest region coal that meets a 90 percent sulfur removal standard if FGD at a given level is applied to the cleaned coal.

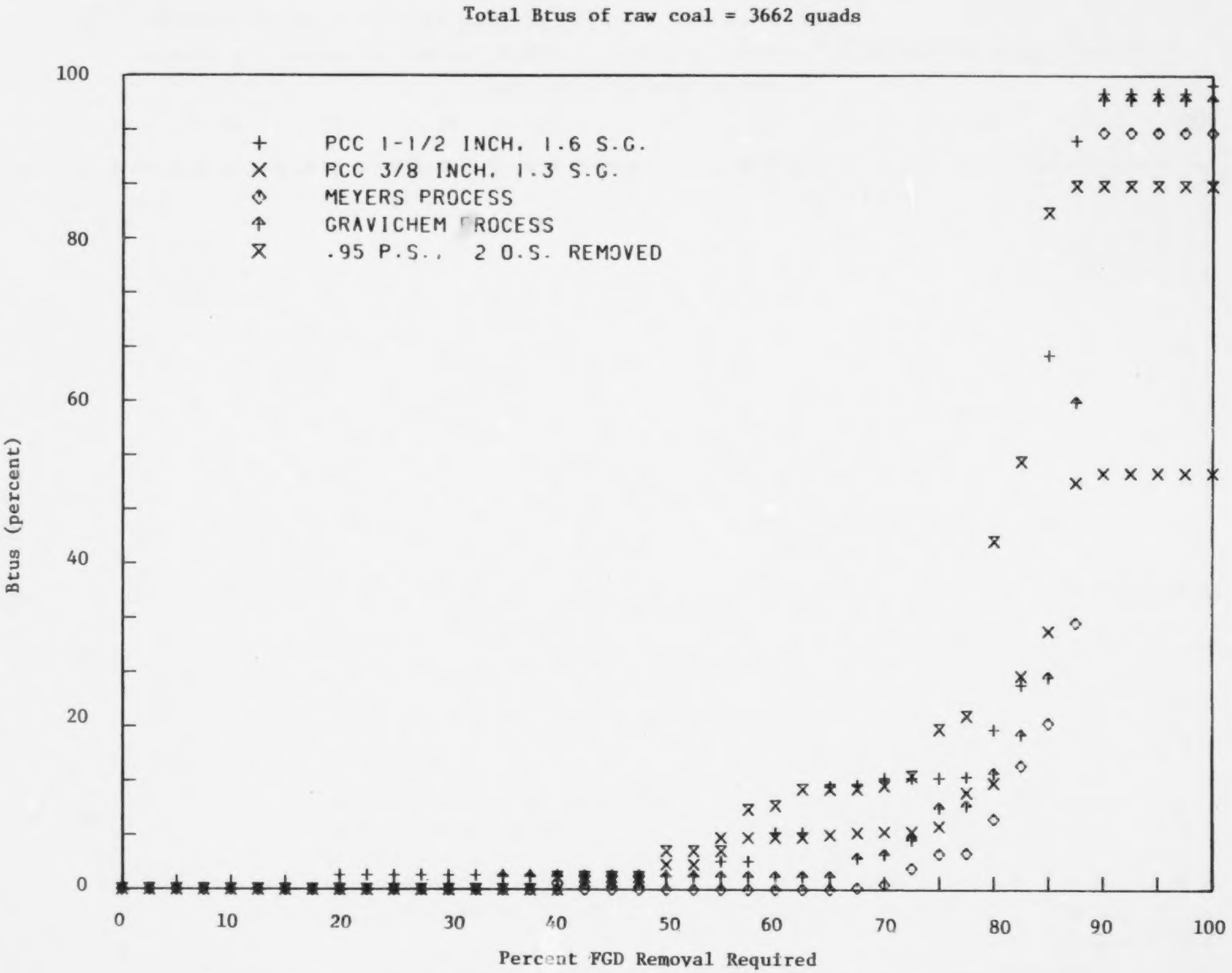

Figure 6. Percent of Western region coal that meets a 90 percent sulfur removal standard if FGD at a given level is applied to the cleaned coal.

Total weight of raw coal = 417 billion tons

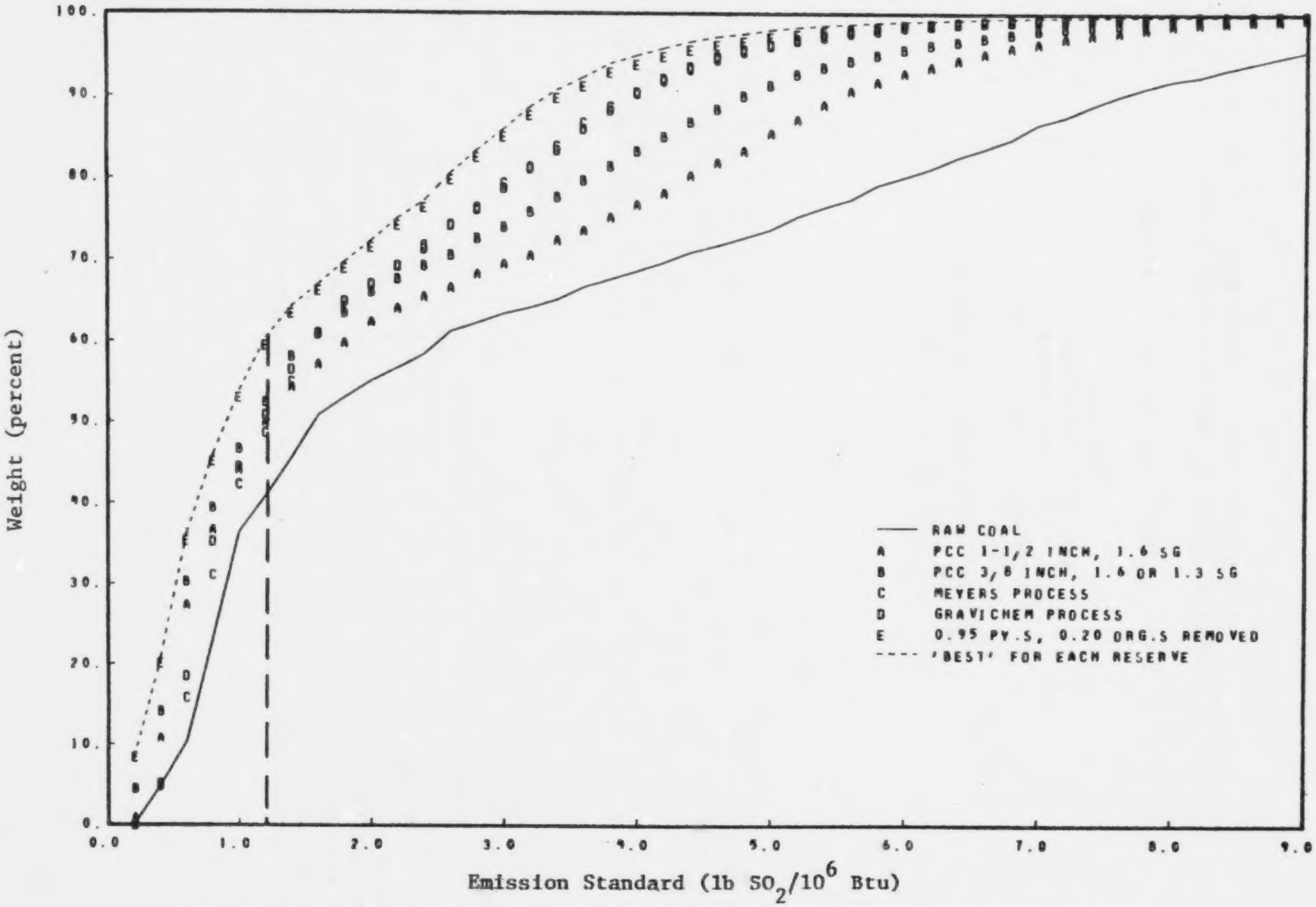

Figure 7. Percent of reserves in the entire U.S.A. that can be cleaned to meet given emission standards.

THE USE OF COAL CLEANING FOR COMPLYING WITH SO_2 EMISSION REGULATIONS

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ABSTRACT

Coal cleaning is an effective technique for reducing the sulfur content of coal so that it can be burned in compliance with SO_2 emission regulations. The potential role for coal cleaning in an overall SO_2 control strategy depends upon the emission regulations and the cleanability of the coal. The several types of SO_2 regulations are reviewed and compared with the ranges of sulfur removal achievable through coal cleaning. The quantities of coal which could be cleaned to various sulfur levels, obtained by combining coal reserve data with coal washability data, are presented. A comparison is made of these quantities with the actual fuel requirements of existing facilities classified according to the regulation each must observe. The results indicate that coal cleaning could make a significant contribution to SO_2 emissions control for boilers which are regulated by SIP's, and to a lesser extent for boilers under current NSPS. The economic factors which will determine the actual role of coal cleaning are discussed. The combined use of coal cleaning and some other control technique, such as flue gas desulfurization (FGD), has potential value in meeting existing NSPS, or in meeting suggested revisions to the utility NSPS. In the latter case credit can be taken for precombustion removal of sulfur by coal cleaning which would reduce the percentage removal requirement for the FGD system.

INTRODUCTION

Coal cleaning can be an effective technique for reducing the sulfur content of coal, thereby reducing the emissions of sulfur oxides when the coal is burned. Various technical and associated environmental aspects of coal cleaning processes are described in many other papers presented at this symposium. The purpose of this paper is to explore how coal cleaning can be used in complying with SO_2 emission regulations.

The potential of coal cleaning in an overall SO_2 emission control strategy depends upon the level and form of the emission regulations, and on the cleanability of the coal. This paper presents a review of the several types of SO_2 regulations, a summary of the ranges of sulfur removal achievable through coal cleaning, a comparison of the quantities of cleanable coal with actual fuel requirements of existing facilities classified according to the regulation each must observe, and an evaluation of how coal cleaning can best be used to comply with SO_2 emission regulations.

SO_2 EMISSION REGULATIONS

The SO_2 emission standards for coal-fired steam generators vary according to the size, age, and location of the facility. Existing boilers are regulated by the State Implementation Plans (SIP's). The SIP's vary from state to state with most states using two or more levels, a low emission limit for plants in metropolitan areas and higher emission limits for plants in non-metropolitan areas. These regulations vary from 0.2 to 8.0 lb $SO_2/10^6$ Btu of boiler heat input. In many states the emission limits apply only to boilers larger than a specified size. Examples of SIP emission limits are given in Table 1.

New Source Performance Standards (NSPS) were promulgated by EPA as required by the 1970 Clean Air Act Amendments. These standards apply to boilers, whether utility or industrial, larger than 250 x 10^6 Btu/hr of boiler heat input, and constructed after the date of promulgation. The emission limit for coal-fired boilers under NSPS is 1.2 lb $SO_2/10^6$ Btu. The 1977 Clean Air Act Amendments significantly modified previous clean air legislation. These Amendments require the use of best available technology, a method of continuous pollution control, and achievement of a percentage reduction in the uncontrolled emissions. EPA is now considering, and will soon propose, revised NSPS for electric utility boilers. The revised NSPS probably will retain a maximum emission limit of 1.2 lb $SO_2/10^6$ Btu, but will add a requirement of 80-90 percent reduction in uncontrolled SO_2 emissions. Uncontrolled emissions less than a minimum level (0.2 to 0.5 lb $SO_2/10^6$ Btu) would be exempt from the percentage reduction requirement Credit for pre-combustion sulfur removal will be given. The revised NSPS probably will apply to utility boilers larger than 250 x 10^6 Btu/hr.

EPA also is considering revised NSPS for industrial boilers. At this time, the form of these revised regulations, e.g. the maximum emission allowable, the percentage reduction requirement, and the size range of boilers to be regulated, is unknown. A summary of these various regulations is given in Table 2.

Variability of Sulfur in Coal

The fact that the composition and properties of coal can vary widely, even within a given coal seam, is an important consideration with respect to emission regulations. Because the sulfur content varies, the average value for sulfur in coal can be used to determine compliance with a given standard only if long-term averaging of the resultant SO_2 emission is permitted. If, however, the emission limit includes a "never to be exceeded" statement, a coal with average sulfur and heat content values which are equivalent to the stated emission limit will be out of compliance approximately half of the time. The net effect of an emission regulation which calls for anything other than long-term averaging is to require the use of coal with a lower average sulfur content so that when upward deviations from the average occur the unit will still be in compliance.

The impact of these considerations is shown in Table 3 in which the average emission level required by different averaging times is listed for various emission limits.

It is apparent that short-term averaging requirements will greatly reduce the quantities of raw coal which could be burned in compliance with any given emission limit, because the average sulfur content required for a 24-hour averaging period is less than one-half of the value required for long-term averaging. There is evidence to suggest that coal cleaning reduces the sulfur variability. If this is the case, coal cleaning would be even more effective in meeting emission standards with short-term averaging periods than would be indicated by the reduction in sulfur content achieved.

EFFECTIVENESS OF COAL CLEANING

The value of coal cleaning as a control technology for meeting the emission regulations described, depends on the amount of sulfur reduction which can be achieved. Cleanability data obtained by the U.S. Bureau of Mines suggest that common commercial physical coal cleaning practice can remove from 28-55 percent of the pyritic sulfur as shown in Table 4. The resulting cleaned coals would, on combustion, produce emissions ranging from 1.1 to 9.0 lb $SO_2/10^6$ Btu. The best current technology can achieve pyritic sulfur reductions of 43-80 percent, and average emission levels of 0.9 - 4.4 lb $SO_2/10^6$ Btu. Research on advanced physical cleaning techniques indicates the potential for removing 90 percent of the pyritic sulfur to yield a product with SO_2 emissions in the range of 0.8 to 3.5 lb $SO_2/10^6$ Btu.

Examination of the ranges in the effectiveness of physical cleaning shows that the technology cannot be employed as the sole control method to meet an 80-90 percent reduction standard. However, the effectiveness of sulfur removal is such that most of the SIP's can be met by burning physically cleaned coal.

Similar data are shown in Table 5 for chemical coal cleaning. Greater reductions in pyritic sulfur can be achieved by chemical cleaning. In addition, some of the processes under development are capable of removing a portion of the organic sulfur. Again, none of the chemical coal cleaning processes could be used alone to meet an 80-90 percent reduction standard, but chemically cleaned coal would be used to meet many of the SIP regulations.

QUANTITIES OF CLEANABLE COAL

In order to evaluate the potential for coal cleaning in meeting SO_2 standards, it is necessary to estimate the amounts of coal which could be cleaned to various levels by using different cleaning processes. Such estimates were developed through an overlay of coal reserve data (U.S. Bureau of Mines 1975), coal cleanability data (U.S. Bureau of Mines 1976), and a third data set consisting of approximately 50,000 records of coal sample analyses. The computer programs which were developed to carry out these calculations are described in another paper presented at this symposium (McCreery and Goodman, 1978).

Several different coal cleaning processes were examined to determine their effects on coal from each of the six major coal producing regions and from the U.S. as a whole The coal cleaning processes considered were:

A. Physical coal cleaning using 1-1/2 inch mesh at 1.6 specific gravity (s.g.)

B. Physical coal cleaning using 3/8-inch mesh at 1.6 s.g. if this produced coal to meet the standard being considered, otherwise 1.3 s.g. was used. An operating penalty of 1 percent energy loss was assumed.

C. Meyers process: for raw coal with greater than 0.2 percent pyritic sulfur, the level of pyritic sulfur is reduced to 0.2 percent. No sulfur reduction takes place if the raw coal pyritic sulfur level is less than 0.2 percent. A 5 percent energy loss was assumed plus an operating penalty of 2 percent energy loss and a weight loss of 10 percent.

D. Gravichem process: crush coal to 14-mesh topsize, separate at 1.3 s.g.; treat sink with Meyers process (with the same energy and weight losses as in C); combine the float and the processed sink.

E. 95 percent pyritic sulfur and 20 percent organic sulfur removed with 10 percent energy loss plus operating penalty of 2 percent energy loss and a weight loss of 15 percent.

F. Physical cleaning using 3/8-inch mesh at 1.3 s.g.; no operating penalty.

G. 95 percent pyritic sulfur and 40 percent organic sulfur removed with 30 percent energy loss.

H. 70 percent organic sulfur removed.

Processes A-E are considered to be realistic processes while F-H are considered to be hypothetical.

An example of the results obtained from these calculations is shown in Northern Applichian coals in Figure 1 in which the percentage of the recoverable reserves of the region, expressed in terms of energy content, is plotted against the SO_2 emission which would result on combustion. Curves are shown for raw coal and for four of the cleaning processes. The interpretation of these curves may be illustrated by considering an emission standard of 1.2 lb $SO_2/10^6$ Btu. From the raw coal curve, 5.3 percent of the reserve, or 91 x 10^{15} Btu, could be burned in compliance. The corresponding values taken from the curves for the various cleaning processes are given in Table 6. The effectiveness of the cleaning processes is apparent as the quantity of compliance coal which could be made available through coal cleaning can be as much as six or seven times that for raw coal.

Separate curves of this type were developed for the deep, strip, and total reserves for each of the six coal producing regions, and for the entire United States. The total United States curves for raw coal and for four of the cleaning processes are shown in Figure 2. The indicated percentages of the reserve and the associated energy contents which could be burned in compliance with a 1.2 lb $SO_2/10^6$ Btu standard are given in Table 7.

An additional series of calculations was made from the reserve/cleanability model to determine the percentage of sulfur in cleaned coal which must be removed by scrubbing to achieve 90 percent overall suflur reduction by the combined control methods. As an example of this type of output, the results for three cleaning processes for the entire United States are shown in Figure 3. The curves show that for a scrubber operating at

70 percent sulfur removal, for example, the following quantities of coal could be used in compliance with a 90 percent reduction standard:

Treatment Method	Percent of Reserve	Energy Content, 10^{15} Btu
PCC, 1-1/2 inch, 1.6 s.g.	5.0	438
Meyers	14.2	1251
95 percent Pyritic S, 20 percent Organic S Removed	17.3	1532

These results indicate that, while coal cleaning alone cannot satisfy a 80-90 percent reduction standard, the combined use of coal cleaning and scrubbing could be an effective approach in that it allows the scrubber to operate at lower and more readily achieved level of sulfur reduction.

COMPARISON OF CLEANABLE COAL QUANTITIES WITH COAL REQUIREMENTS

A procedure was developed to relate industrial energy requirements to the quantities of raw coal and of coal that could be made available by application of various cleaning processes which could be used to meet prescribed SO_2 emission standards. Calculations have been completed for the Northern Appalachian Region.

Quantities of raw coal and cleaned coal meeting various standards were obtained from the reserve/cleanability model as discussed above. Industrial demand was determined from a characterization of existing industrial fuel burning facilities according to state, SIP requirements within the state, capacity, and fuel. SIP requirements were simplified by using at most two SIP standards (basically metropolitan and non-metropolitan) in any one state. The major source of data was the FEA survey of "Major Fuel Burning Installations (MFBI)", which gave data as of 1974. Survey data included itemization of details for each combustor above 100 x 10^6 Btu/hour.

The MFBI survey required listing of total capacity at each installation but did not require an itemized breakdown for "small' combustors, defined as those below 100 x 10^6 Btu/hour. Thus, it was necessary to synthesize these small-combustors constitute approximately 40 percent of the total industrial fuel burning capacity.

The procedure for this synthesis consisted of applying data from an EPA boiler survey (Paddock and McMann, 1975) on capacity distribution to estimate the allocation among coal, residual, distrillate, gas, and other for "small" boilers. The MFBI total of "small" and "large" boilers and "large" non-boilers was subtracted from the entire capacity in each region thus determining the total of "small" non0boilers. There are no data on capacity distributions among fuels for "small" non-boilers. These capacities were distributed assuming that the ratios of "small coal non-boiler capacity" to "small gas non-boiler capacity" to residual, etc. were the same as similar ratios for large boilers. Thus, it was possible to determine "small" non-boiler capacities by different.

The total current industrial demand in each SIP region is obtained by adding "large" boiler, "small" boiler, "large" non-boiler, and "small" non-boiler capacities for each fuel. The potential for coal utilization consists of the total of coal, residual, distillate, and gas combustor capacities. Facilities utilizing "other" fuels were not considered convertible to coal because the "other" fuel is hog fuel, refinery off-gas, and other waste ot by-product materials for which there is little other demand. Table 8 illustrates these results for the coal-producing states in the Northern Appalachian Region.

A "coal use" model was developed which assumes that a demand area will use coal with the highest sulfur level possible to meet its $S0_2$ emission standard. As these reserves are depleted, the area then uses coal with lower and lower sulfur levels. This procedure would be approximate in reality (over a long time period) if the cost of coal increases with a lowering sulfur content. Thus, a large capacity user with a fairly non-restrictive SIP, e.g., non-metropolitan Ohio, will ultimately be using the same reserves as a smaller capacity user with a less restrictive SIP, e.g., non-metropolitan Maryland. The model is run until all of the coal in the region is consumed with the various users running out of coal (depending on supply, SIP, and demand) at various times. Table 9 illustrates results for the case if only the coal producing states are users. A load factor of 1.0 was used in these runs. Load factors vary widely but typically are no more than 0.5. It should be noted that the Northern Appalachian coal reserves considered do not include the very high quality coal in Southern West Virginia (a part of the Southern Appalachian coal producing region). The processes designated in Table 9 are the same as listed previously.

The results shown in Table 9 are valuable in comparing the usefulness of various coal cleaning processes in preparing coal to meet existing SIP's for existing facilities. For example, the results indicate that coal cleaning processes may be used to increase the supply of coal to satisfy SO_2 emission standards of 1.6 lbs $SO_2/10^6$ Btu by a factor of up to 3 or 4 over raw coal. The absolute magnitudes of the years of available coal are not meaningful at this stage of the analysis since other consuming states and other coal uses are not included. Analyses extended to all regions and to the utility sector are being completed and the results will be published in an EPA report.

CONTROL TECHNOLOGY COSTS

The results which have been presented show that large quantities of coal can be cleaned to meet various SO_2 emission limits. The extent to which coal cleaning will be actually employed as an SO_2 control technique will be determined in part on the basis of comparative costs. For the purposes of this paper only a generalized overview of costs is presented.

Coal cleaning costs depend upon a number of factors which include:

o Plant complexity (level of cleaning)

- Plant Size and Operating Factor
- Coal Replacement Costs
- Pollution Control Costs
- Reliability and Product Control
- User Cost Benefits
- Finance Considerations

Ranges of annualized costs for both physical and chemical coal cleaning are given in Table 10. Chemical cleaning costs are more than a factor of two higher than those for physical coal cleaning.

The costs of flue gas desulfurization (FGD) also depend on a number of factors which include:

- Type of FGD System
- Boiler Size and Operating Factor
- Sulfur Removal Requirements
- Pollution Control Costs
- Reliability and Control
- Finance Considerations

Estimated annualized FGD costs, based on lime-limestone scrubbing, are shown in Figure 4. The costs range from about $\$1.00/10^6$ Btu for smaller boilers using high-sulfur coal at a low operating factor to about $\$0.30/10^6$ Btu for large boilers burning low-sulfur coal at a high operating factor.

A comparison of these cost ranges is given in Figure 5. General conclusions from the comparison are as follows:

- Physical coal cleaning offers cost savings over FGD especially for small boilers with low capacity factors.
- Coal cleaning used in conjunction with FGD may be cost effective over FGD alone, in some cases, since the cleaned coal requires less sulfur removal than uncleaned coal.
- Chemical coal cleaning may be cost effective as compared with FGD in some smaller boilers with low capacity factors.

Because the costs of coal cleaning and FGD are sensitive to a number of different factors, site-specific analysis of costs is required to determine the most cost effective control technique for each site.

CONCLUSIONS

The greatest role for physical coal cleaning appears to be in meeting state SO_2 emission regulations on existing boilers. Cleaning methods exist for preparing coal to meet many of the various SIP levels and the estimated quantities of cleanable coal are substantial.

Since a number of coals can be cleaned sufficiently to comply with a standard of 1.2 lb $SO_2/10^6$ Btu, coal cleaning, also can fill a role in meeting current NSPS for coal-fired steam generators.

Coal cleaning cannot be used alone to meet an 80-90 percent reduction standard, now under consideration. However, the use of cleaned coal would allow a scrubber or other control system to be operated at a lower level of sulfur reduction. The combination of techniques may offer cost savings in some cases. Further, given the current uncertainty over the ability of scrubbers to operate consistently at high levels at high levels of sulfur reduction, the use of cleaned coal might be the only means of complying with an 80-90 percent reduction requirement over the near term.

The nature of revised NSPS for industrial boilers is unknown at this time. However, the size range of regulated boilers may include smaller than is the case for utility boilers which would increase the potential for coal cleaning in view of the cost advantages for smaller boilers.

The current cost projections for chemical coal cleaning indicate that the most probable applications for such processes will be to provide lower sulfur levels than can be achieved by physical cleaning where required by a particularly stringent regulation.

CONVERSION FACTORS

lb = 0.454 kg

Btu = 1055.6 joule

10^6 Btu = 1.056 GJ

lb/10^6 Btu = 0.430 kg/GJ

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The Reserve Base of U.S. Coals by Sulfur Content, IC 8680 and IC 8693, U.S. Bureau of Mines, 1975.

Sulfur Reduction Potential of U.S. Coals, RI 8118, U.S. Bureau of Mines, April, 1976.

"An Evaluation of the Desulfurization Potential of U.S. Coals", J. H. McCreery and F. K. Goodman, Symposium on Coal Cleaning to Achieve Energy and Environmental Goals, Hollywood, Florida, September 1978.

Paddock, R. E. and McMann, D.C., "Distributions of Industrial and Commercial-Institutional External Combustion Boilers", EPA 650/2-75-021 (February, 1975).

Table 1. Typical State Emission Limits for Coal-Fired Boilers (lb $SO_2/10^6$ Btu)

STATE	METROPOLITAN AREAS	NON-METROPOLITAN AREAS
ALABAMA	1.8	4.0
COLORADO	0.2	0.2
ILLINOIS	1.8	6.0
IOWA	5.0	5.0
KENTUCKY	1.2	5.7
OHIO	1.4	4.5
PENNSYLVANIA	0.7	4.0
WEST VIRGINIA	2.8	2.8

Table 2. SO_2 Emission Standards for Coal-Fired Steam Generators

	SULFUR REDUCTION, PERCENT	EMISSION LIMITS, LB $SO_2/10^6$ BTU
EXISTING BOILERS (SIP'S)	–	0.2–8.0
CURRENT NSPS FOR STEAM GENERATORS	–	1.2
REVISED NSPS FOR UTILITY BOILERS[a]	80–90	1.2 MAX. 0.2 FLOOR
NSPS FOR INDUSTRIAL BOILERS	UNKNOWN	UNKNOWN

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[a] Values under consideration.

Table 3. Effect of Averaging Time on Average Coal Sulfur Level Required for Compliance

EMISSION LIMIT, LB $SO_2/10^6$ BTU	AVERAGE COAL SULFUR VALUE REQUIRED, LB $SO_2/10^6$ BTU		
	LONG-TERM AVERAGE	30-DAY AVERAGE[a]	24-HOUR AVERAGE[b]
1.2	1.2	0.92	0.58
0.8	0.8	0.62	0.39
0.4	0.4	0.31	0.19

(a) Assumes relative standard deviation of 10 percent.
(b) Assumes relative standard deviation of 36 percent.

Table 4. Physical Desulfurization[a]

CLEANING TECHNIQUE	AVERAGE PYRITE REMOVED, PERCENT	AVERAGE REDUCTION IN LB $SO_2/10^6$ BTU, PERCENT	AVERAGE EMISSION LEVEL ON COMBUSTION, LB $SO_2/10^6$ BTU
UNCLEANED COAL	–	–	1.1–9.0
COMMON COMMERCIAL PRACTICE	28–55	11–40	0.9–6.5
BEST CURRENT COMMERCIAL TECHNOLOGY	43–80	16–55	0.9–4.4
BEST POTENTIAL TECHNOLOGY	90	30–60	0.8–3.5

(a) Based on data from Bureau of Mines RI 8118 for averages from each of six coal regions.

Table 5. Chemical Desulfurization[a]

CLEANING TECHNIQUE	AVERAGE PYRITE SULFUR REMOVED, PERCENT	AVERAGE ORGANIC SULFUR REMOVED, PERCENT	AVERAGE REDUCTION IN LB $SO_2/10^6$ BTU ·PERCENT	AVERAGE EMISSION LEVEL ON COMBUSTION, LB $SO_2/10^6$ BTU
UNCLEANED COAL	–	–	–	1.2–9.0
PYRITE LEACHING	95	0	32–65	0.8–3.2
BEST AVAILABLE TECHNOLOGY	95	25	48–73	0.6–2.5
BEST PRACTICAL TECHNOLOGY	95	40	58–77	0.5–2.0

(a) Based on data from Bureau of Mines RI 8118 for averages from each of six coal regions.

Table 6. Northern Appalachian Coals

TREATMENT METHOD	AMOUNT OF COAL IN COMPLIANCE WITH 1.2 LB $SO_2/10^6$ BTU PERCENT OF RESERVE	 ENERGY CONTENT, 10^{15} BTU
RAW COAL	5.3	91
PCC, 1-1/2 INCH, 1.6 S.G.	12.8	221
PCC, 3/8 INCH, 1.6 OR 1.3 S.G.	24.7	427
MEYERS PROCESS	29.5	509
95% PYRITIC S, 20% ORG. S REMOVED	36.8	636
"BEST" FOR RESERVE	40.9	707

Table 7. United States Coals

TREATMENT METHOD	AMOUNT OF COAL IN COMPLIANCE WITH 1.2 LB $SO_2/10^6$ BTU	
	PERCENT OF RESERVE	ENERGY CONTENT, 10^{15} BTU
RAW COAL	36.8	3252
PCC, 1-1/2 INCH, 1.6 S.G.	45.1	3987
PCC, 3/8 INCH, 1.6 OR 1.3 S.G.	49.2	4347
MEYERS PROCESS	51.3	4534
95% PYRITIC S, 20% ORG. S REMOVED	57.2	5050
"BEST" FOR RESERVES	57.2	5050

Table 8. Industrial Combustor Capacities (Excluding "Other" Fuel) For Coal-Producing Areas of the Northern Appalachian Region

State	Coal	Residual	Distillate	Gas	Total
Maryland, Metro	3.310	3.295	9.135	10.229	25,968
Maryland, Non-Metro	1.105	1.750	0.000	0.727	3,583
Ohio, Metro	27,447	5,847	3.702	38.512	75.508
Ohio, Non-Metro	24.545	5.222	0.164	19.040	48.972
Pennsylvania, Metro	26.483	36.970	2.641	29.939	96.033
Pennsylvania, Non-Metro	29.838	3.885	0.907	7.171	41.801
West Virginia	19.187	4.961	0.173	4.565	28.886
Northern Appalachian	131.916	61.930	16.721	110.183	320.751

Table 9. Years of Available Coal in the Northern Appalachian Region Using Various Cleaning Processes to Satisfy the Coal Producing States' Current Aggregate of Industrial Coal, Residual, Distillate, and Gas Combustor Capacities

State or Section of State	SIP lbs $SO_2/10^6$ Btu	Years of Available Coal Using Raw Coal or Each of the Designated Processes								
		Raw	A	B	C	D	E	F	G	H
Pennsylvania (Metropolitan)	0.8	23	82	267	123	205	370	205	308	164
Ohio (Metropolitan)	1.4	173	311	447	679	641	641	428	603	233
Maryland (Metropolitan)	1.6	173	311	447	684	641	641	428	603	233
West Virginia	2.6	586	880	816	832	816	720	800	768	683
Pennsylvania (Non-Metropolitan)	3.0	586	880	816	832	816	720	800	768	1,038
Maryland (Non-Metropolitan)	3.5	1,013	880	816	832	816	720	800	768	1,089
Ohio (Non-Metropolitan)	4.5	1,013	880	816	832	816	720	800	768	1,086

Table 10. Annualized SO_2 and Particulate Control Costs ($\$/10^6$ Btu)[a]

TECHNIQUE	MINIMUM[b]	MAXIMUM[c]
PHYSICAL COAL CLEANING	0.26	0.46
CHEMICAL COAL CLEANING	0.60	1.13

---

[a] Includes $\$0.10/10^6$ Btu for particulate control.

[b] Minimum costs correspond to 40,000 million Btu/hr plant capacity and $\$0.05/10^6$ Btu coal replacement costs.

[c] Maximum costs correspond to 10,000 million Btu/hr plant capacity and $\$0.18/10^6$ Btu coal replacement costs.

ESTIMATED CLEANING POTENTIAL OF
NORTHERN APPALACHIAN COALS

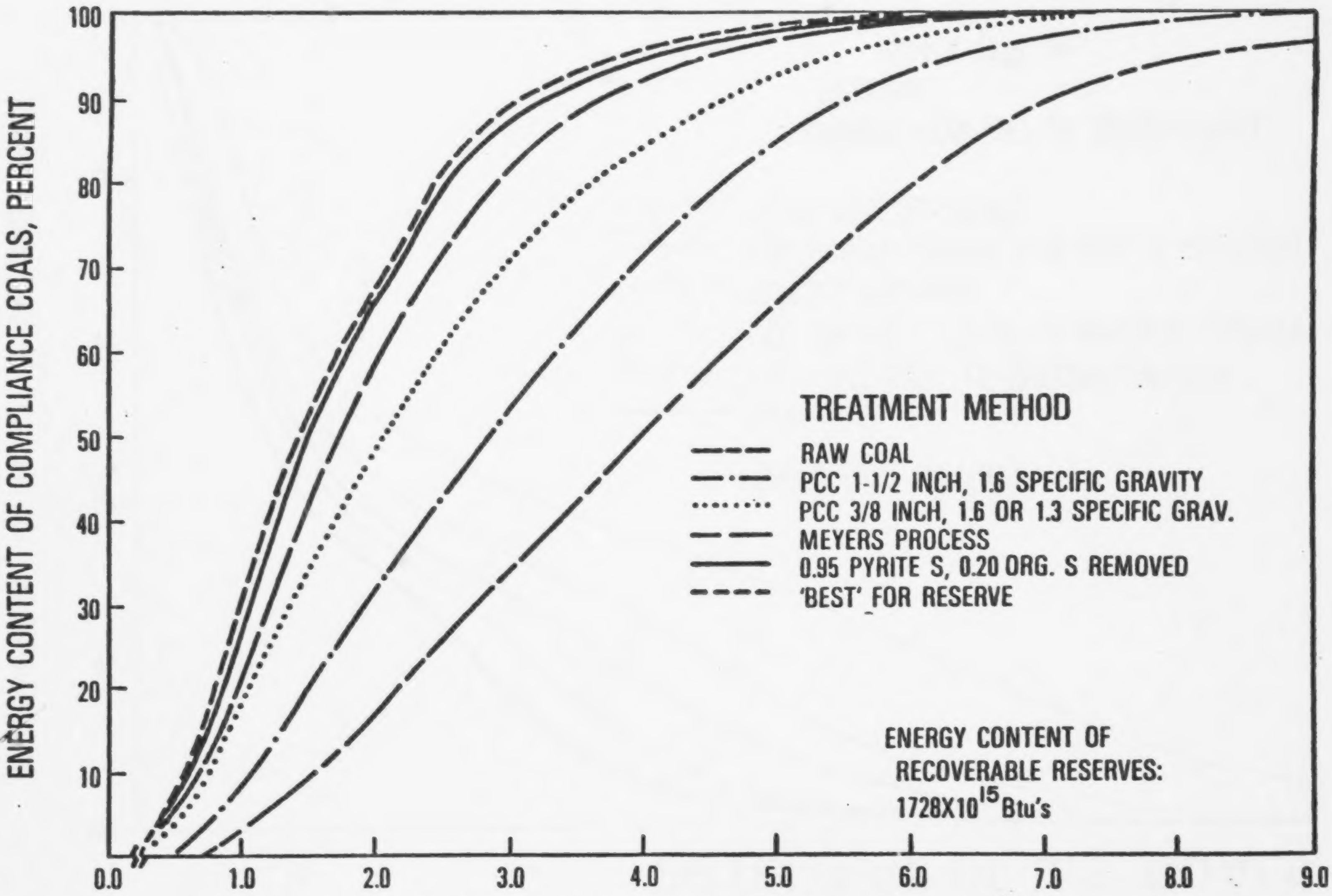


Figure 1. Coal Sulfur Emission on Combustion, lb $SO_2/10^6$ Btu

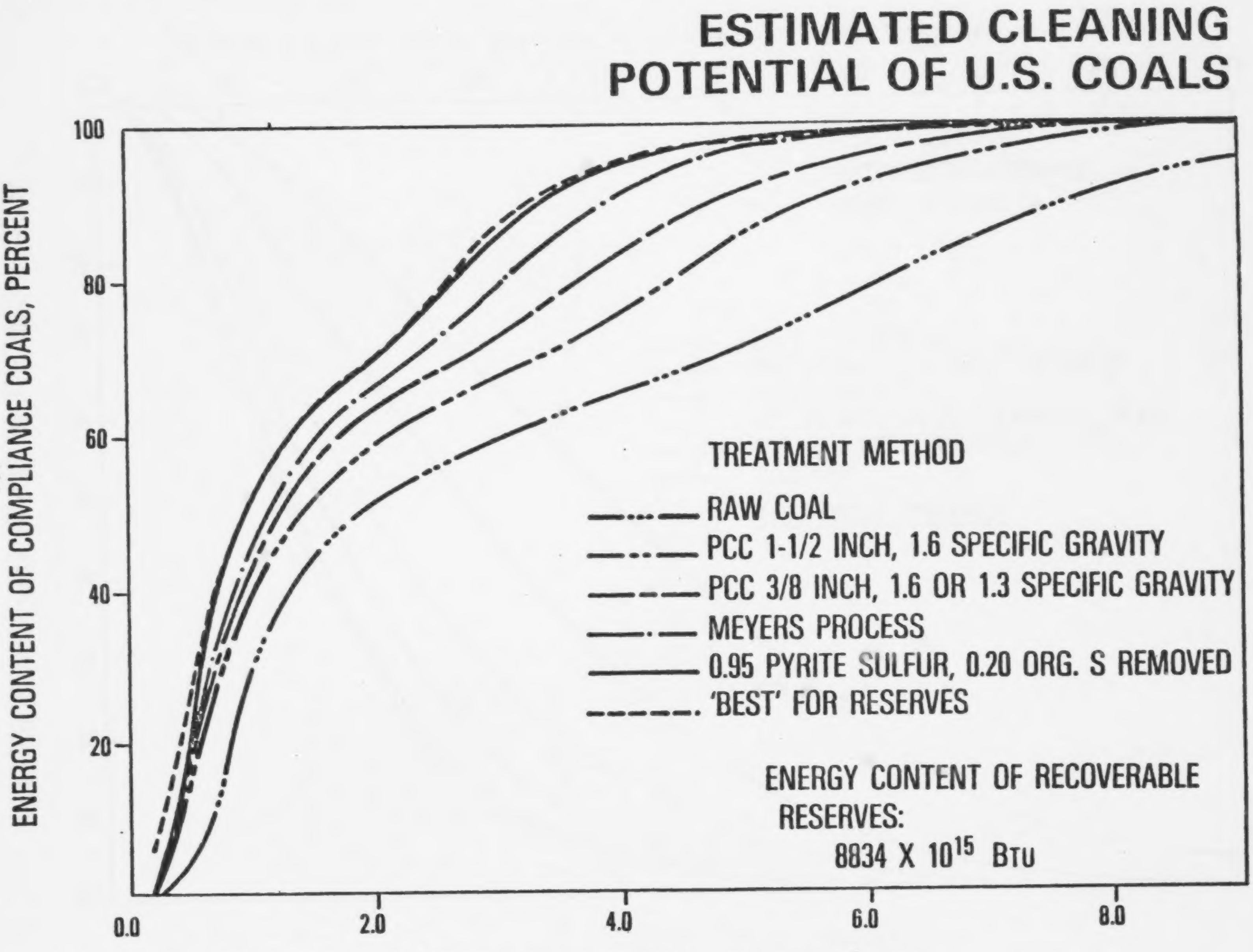
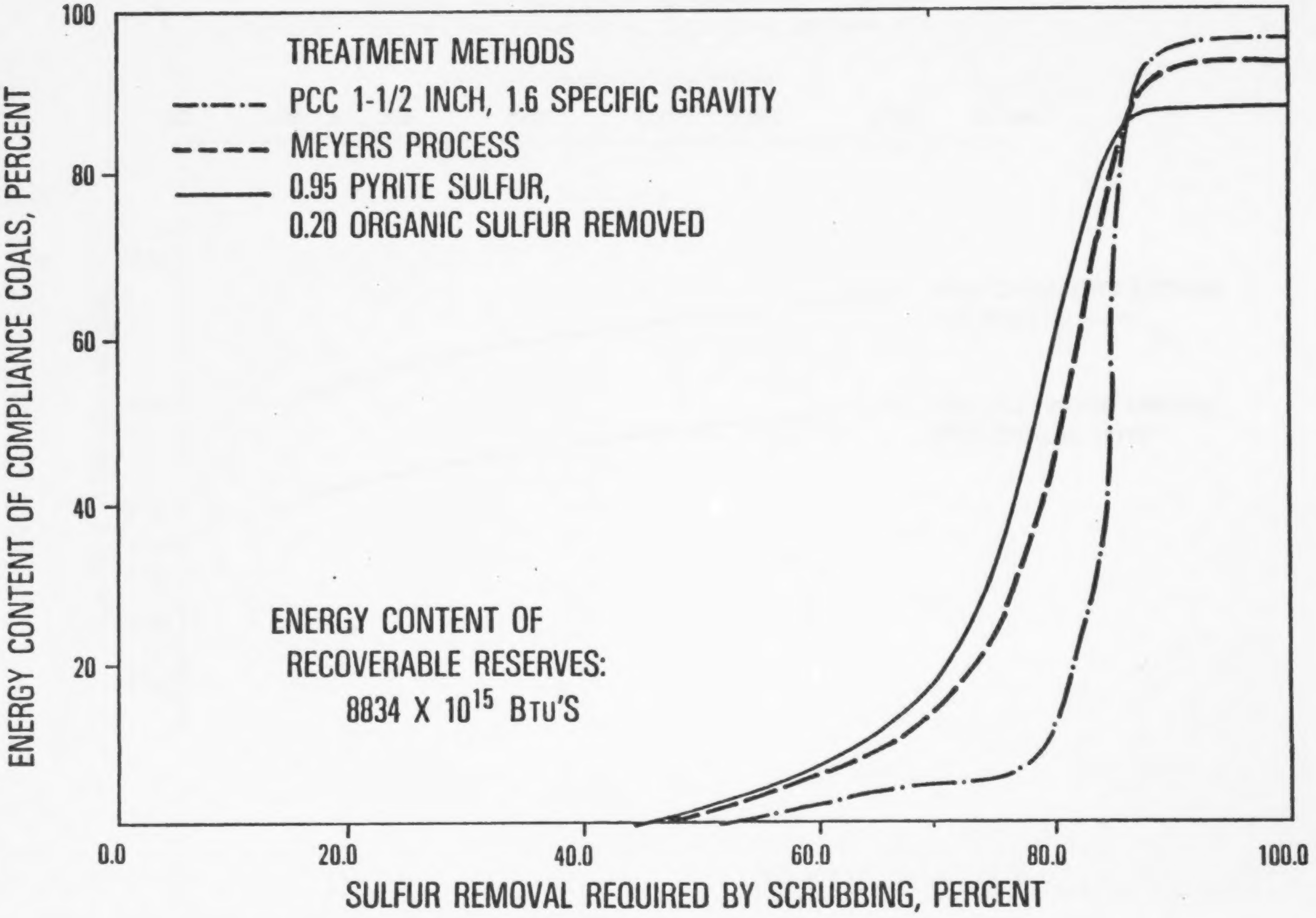


Figure 2. Coal Sulfur on Combustion, lb $SO_2/10^6$ Btu

Figure 3. Estimated Compliance Coals Available Through Cleaning and Scrubbing to Meet Requirement of 90 Percent Sulfur Reduction



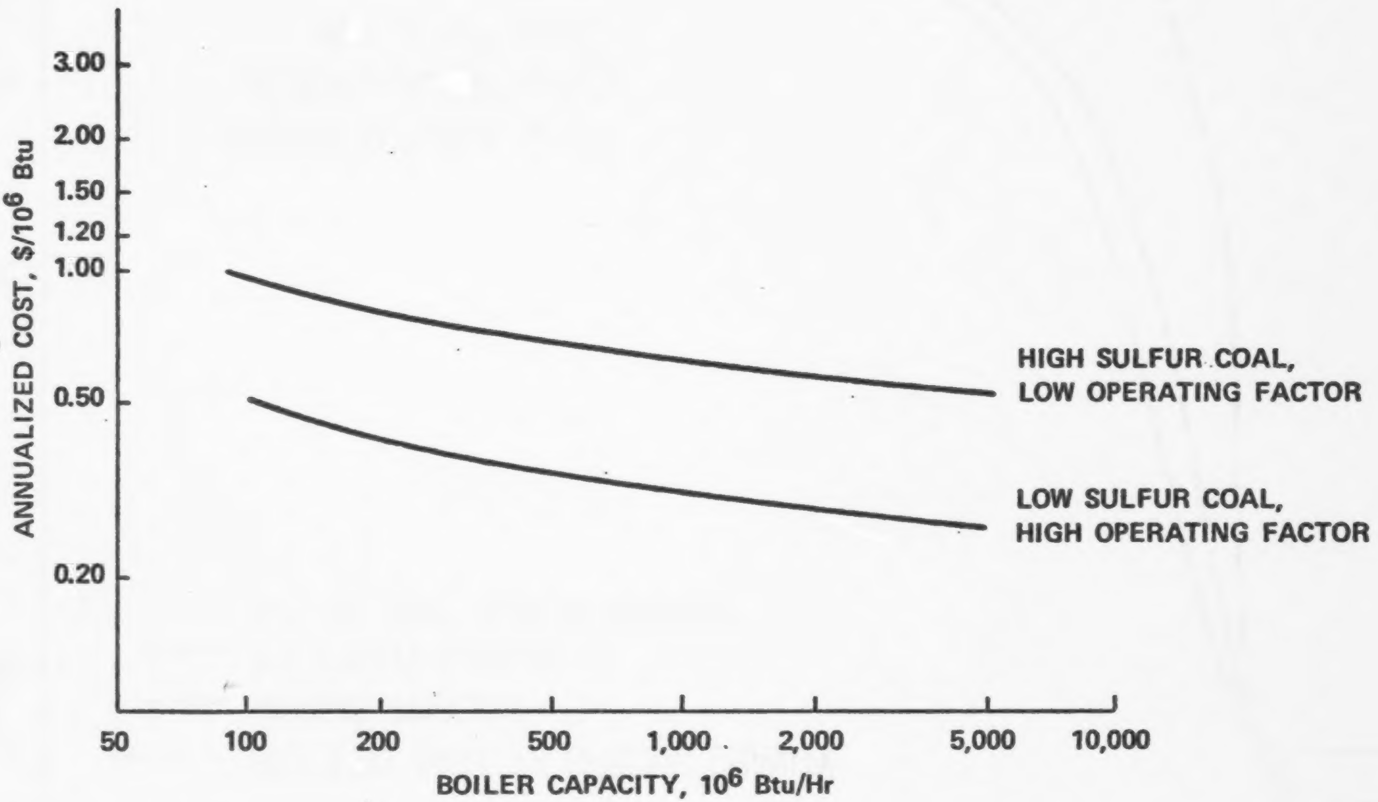
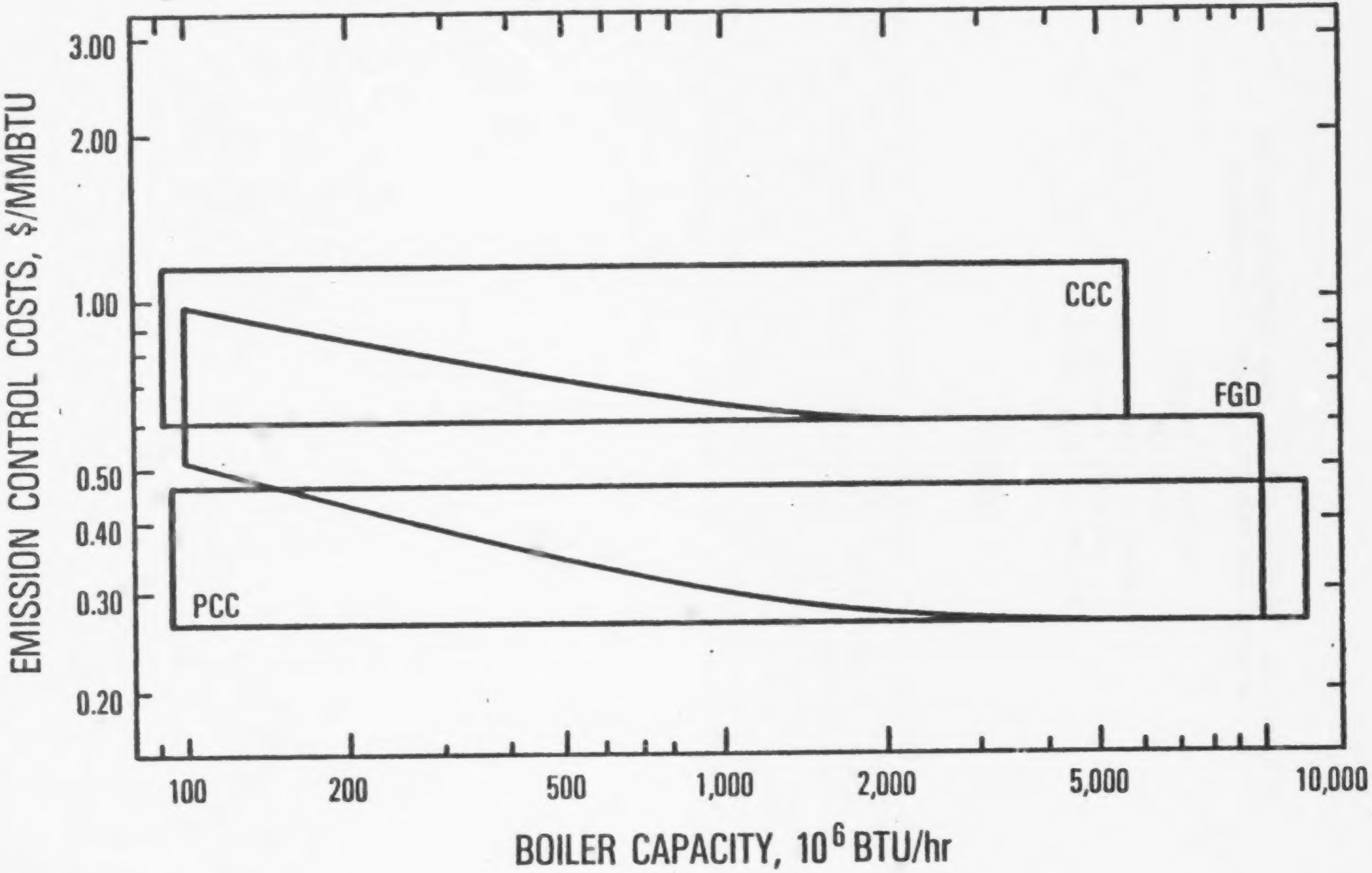


Figure 4. Estimated Annualized FGD Cost Ranges for Sulfur and Particulate Emission Control (Based on Lime-Limestone Scrubbing)

Figure 5. Annualized SO_2 and Particulate Control Costs



STATISTICAL CORRELATIONS ON COAL DESULFURIZATION BY CRUSHING AND SPECIFIC GRAVITY SEPARATION

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ABSTRACT

The weight fractions for washability data for Homer City coal (Feed No. 1) are represented by Rosin-Rammler distributions. Excellent fits are obtained for the distribution of weight, according to size, for each of 12 specific gravity fractions. The characteristic size parameters and dispersion parameters show some non-uniform behavior across the various levels of specific gravity. This behavior is currently under study in an effort to obtain a surface that can be used as a general basis for interpolating among coarse washability data to obtain more refined washability data.

INTRODUCTION

Washability data for coal is costly to generate, especially when it is desired to obtain precise estimations of weight, pyritic sulfur, total sulfur, and ash according to, say, 12 specific gravity fractions for each of 9 size fractions. Such detailed analyses appear to be required in order to properly determine which (specific gravity/size)-fractions are most affected by the various coal cleaning processes, by related coal cleaning equipment, and by the various design parameters associated with such equipment. Good predictions of the output flow rates for clean, middling, and refuse coal requires refined washability data. Even the precisions of computer simulations of coal cleaning processes and equipment are likewise constrained by the available level of refinement of coal washability data. The results reported below are the initial results of an effort to identify a quantitative method for interpolation among limited washability data. By interpolation such a method would permit the refinement of coarse washability data, and would also be expected to identify the minimum number of washability measurements required to achieve a specified precision.

METHOD

In this effort several interpolation methods have been briefly examined. These methods include empirical curve fitting with splines and polynomials, and a more traditional procedure based on the Rosin-Rammler distribution.

In general, it is expected that whenever refined washability data are available, several different interpolation methods are likely to be acceptable. However, when the washability data are coarse, as in R8118 with 3 or 4 specific gravity fractions and 3 size fractions, it is expected that some assumed distributional form, such as the Rosin-Rammler distribution, will be essential in order to compensate for the severely limited washability information.

It is exceedingly important to assume a correct distributional form for interpolating washability data. In effect, with severely limited data, there is no satisfactory way to test the correctness of the assumed distributional form. In statistical terms, some of the limited degrees of freedom are lost in estimating the parameters of the distribution. As a consequence, except for the most extreme cases, the assumed distributional form can neither be conclusively accepted nor rejected by the data.

Because the Rosin-Rammler distribution has a long history of successfully representing size distribution data for coal, (Leonard and Mitchell, 1968) this distribution is being considered as the primary candidate distribution. Previous efforts known to the author have fitted the Rosin-Rammler distribution to size data without regard to specific gravity. In contrast, the strategy used in this effort consists of first determining whether a separate Rosin-Rammler distribution gives a good fit to the size-fraction data within each specific-gravity fraction. That is, if 12 specific-gravity fractions are available, then 12 different Rosin-Rammler curves are fitted to the data. If suitably well-behaved, these curves, in turn, are then regarded as parallel slices from a mathematical surface representing all of the data. Finally the resulting

Rosin-Rammler surface would then be used to interpolate among the actual data values, and thereby "refine" the washability data to the extent required.

Because the Rosin-Rammler distribution has been successfully used to fit size-distribution data, as a composite over all specific gravities, it appears to be a good candidate for fitting the size-distribution data for each separate specific-gravity fraction. However, it should be noted that washability data are usually presented as distributions of percent weight, sulfur, ash, etc., according to specific gravity, for each size fraction. For the present effort the data are first re-cast to express the distributions, according to size fraction, for each specific gravity fraction.

Estimation Procedure

The cumulative form of the Rosin-Rammler distribution is given as follows·

$$F(x) = 1 - \exp\,[-(x/d)^n], \quad 0 \leq x,$$

where d denotes the characteristic diameter and n denotes the dispersion parameter. Thus, F(x) gives the fraction of the distribution associated with a size less than, or equal to, x. It is seen from the above expression that if x is set equal to the characteristic size, then F(d) = 1 - (1/e), so that approximately 63 percent of a Rosin-Rammler size distribution consists of sizes less than the characteristic size.

Limited examinations have been made of several different methods for estimating the parameters d and n. In addition to graphical methods these methods include the method of maximum likelihood with correction for bias (Fishman, 1973) and least squares regression (Hald, 1952). To date the most satisfactory results are obtained by applying least squares regression to the following logarithnmic form of the Rosin-Rammler distribution:

$$\ln\ [\ln(1-F(x))^{-1}] = n[\ln x] - n[\ln d].$$

This expression is seen to correspond to a linear regression form:

$$Y = AX + B,$$

where X and Y correspond to $\ln x$ and $\ln[\ln(1-F(x))^{-1}]$, respectively; and the regression parameters A and B are equated to n and $-n[\ln d]$, respectively. The regression estimate $\hat{A}$ is taken to be a direct estimate of n; the regression estimate $\hat{B}$ is set equal to $-n[\ln d] = -\hat{A}[\ln d]$ so that d is indirectly estimated by $d = \exp(-\hat{B}/\hat{A})$. In contrast to the ideal situation, the estimators of n and d are thus seen to be interrelated. However, this deficiency does not appear to be important for the data examined to date.

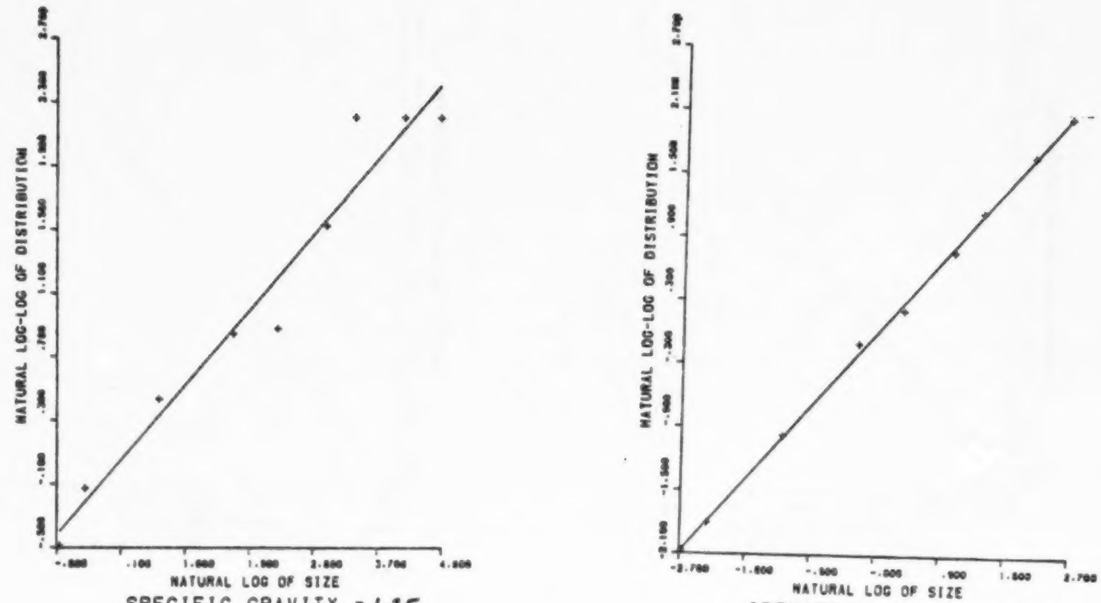
It must also be noted that the Rosin-Rammler distribution accomodates sizes that are distributed over the entire positive range. Arbitrarily large sizes are theoretically permitted provided the associated level of probability is sufficiently small.

Actual size distributions are truncated in that no sizes larger than a truncation size, say 5/4 inch, will occur in the real coal sample. This means that the actual empirical distribution will have 100 percent of the size distribution smaller than the truncation size, 5/4 inch for example. The theoretical Rosin-Rammler distribution can never have 100 percent of the size distribution smaller than any fixed finite truncation size. This means that it is frequently necessary to estimate how much truncation has occurred, and make a suitable correction for such truncation, before fitting the empirical size distributions to a theoretical Rosin-Rammler distribution. An iterative procedure is used to correct for truncation in the results reported below.

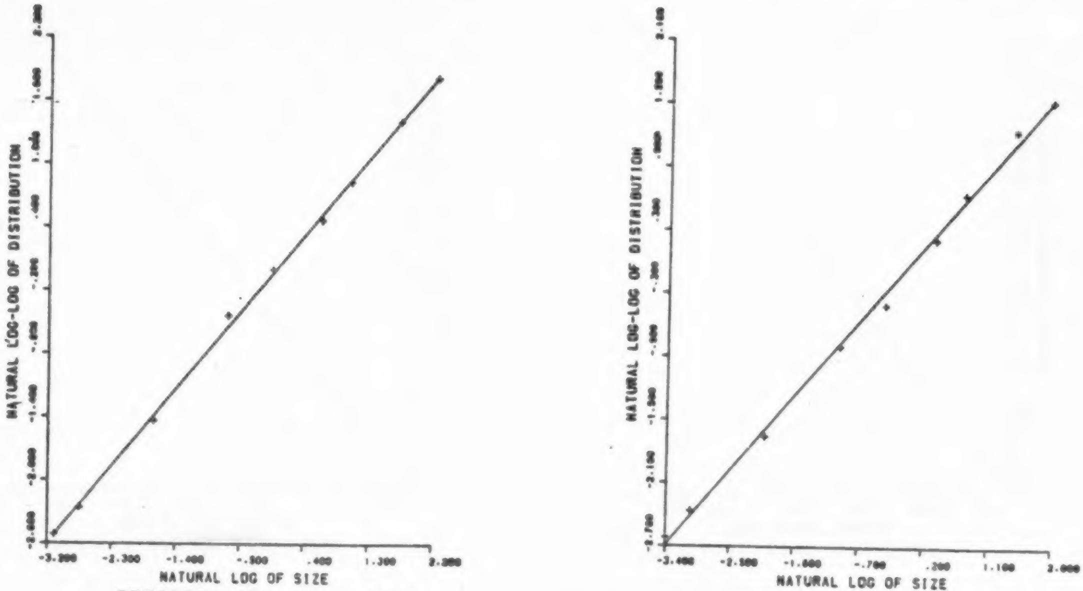
Results

Figure 1 shows the empirical data (corrected for truncation) and the fitted Rosin-Rammler distributions for the percent weight distributions for Homer City coal, Feed No. 1., for the specific gravities shown on each caption. In general, the results show that separate Rosin-Rammler distributions provide excellent representations of the size-distribution data associated with each specific gravity fraction.

Table 1 shows the numerical estimates of the characteristic size d and the dispersion parameter n for each specific gravity fraction for the individual fitted Rosin-Rammler distributions.

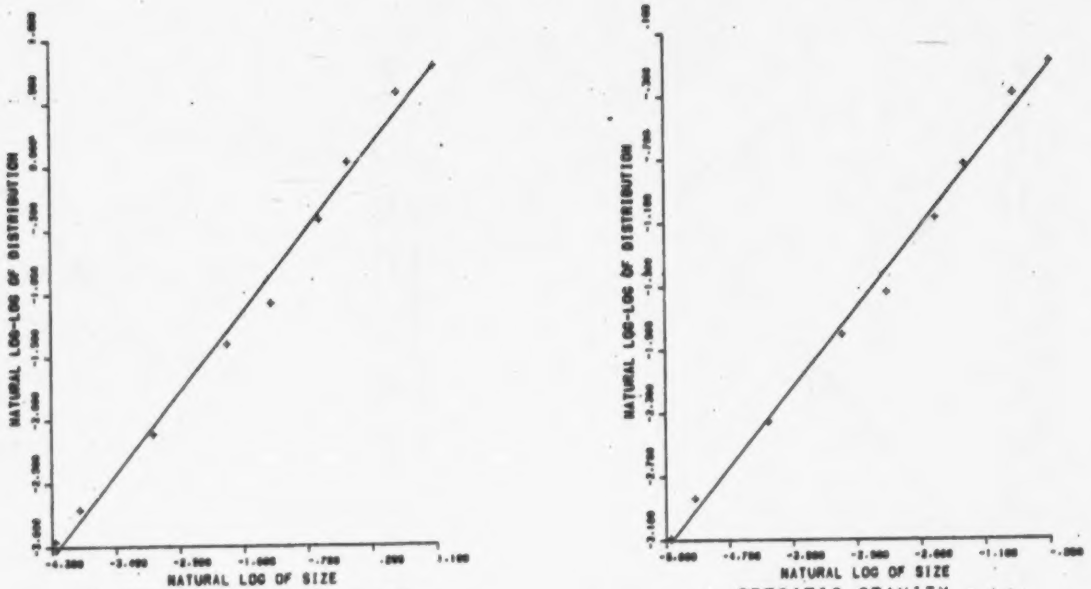


SPECIFIC GRAVITY = 1.26 SPECIFIC GRAVITY = 1.27



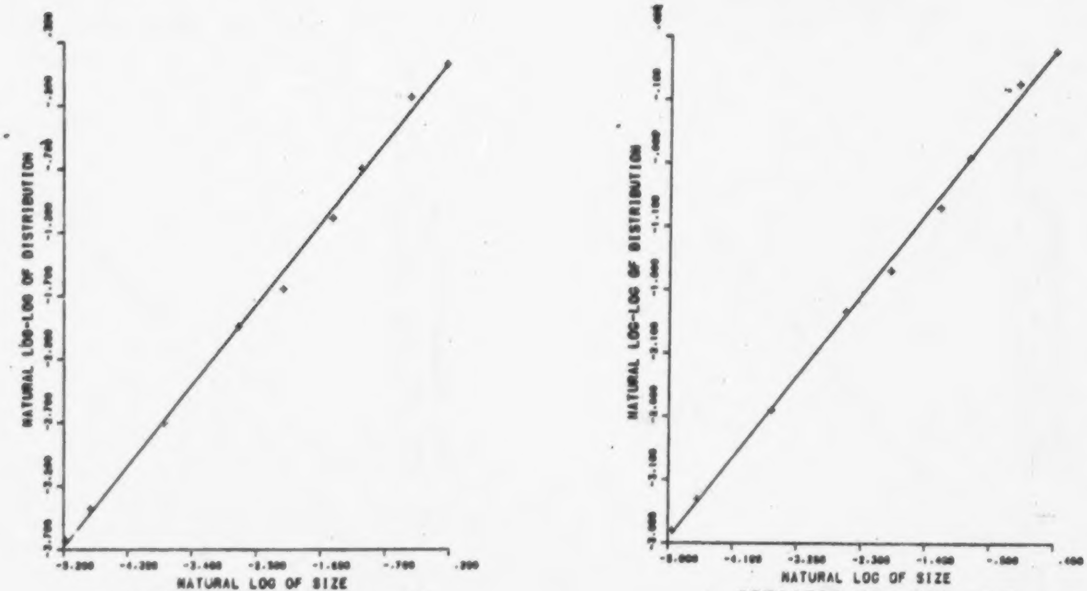
SPECIFIC GRAVITY = 1.30 SPECIFIC GRAVITY = 1.32

FIGURE 1. Rosin-Rammler Representations of Weight Percent, According to Size Fraction, For Each Specific Gravity Fraction For Homer City, Feed No. 1, Washability Data



SPECIFIC GRAVITY = 1.35

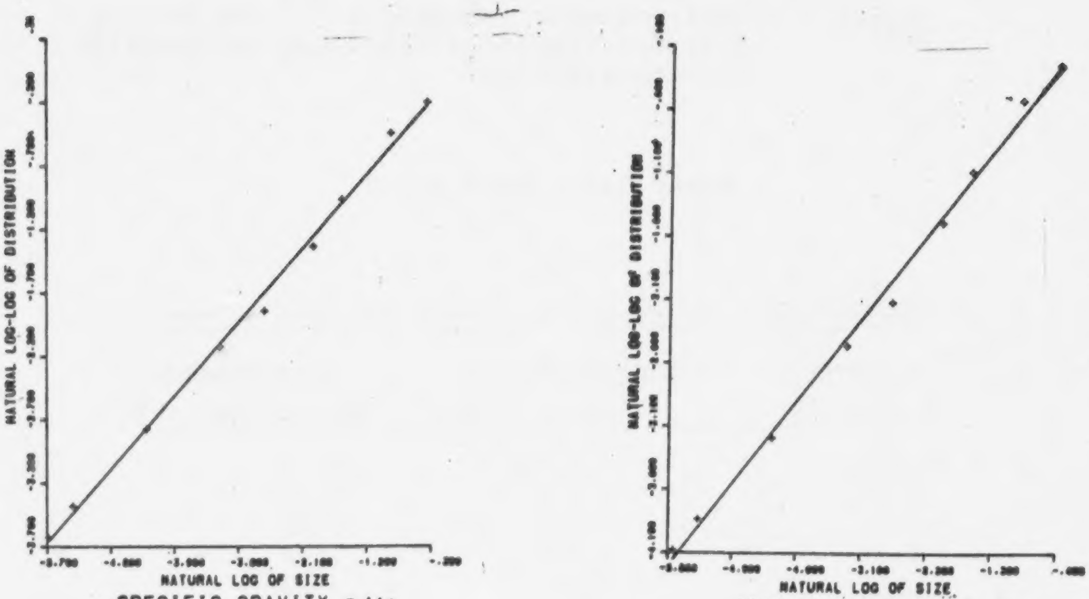
SPECIFIC GRAVITY = 1.40



SPECIFIC GRAVITY = 1.45

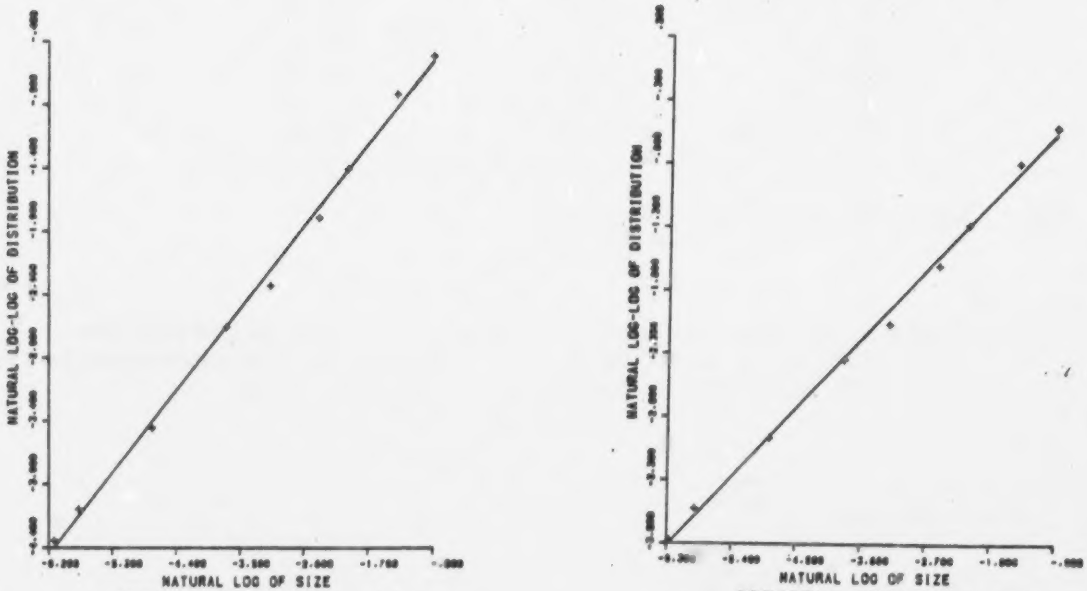
SPECIFIC GRAVITY = 1.50

FIGURE 1. (Continued)



SPECIFIC GRAVITY = 1.60

SPECIFIC GRAVITY = 1.70



SPECIFIC GRAVITY = 1.90

SPECIFIC GRAVITY = SINK

FIGURE 1. (Continued)

TABLE 1. Rosin-Rammler Parameters (1) for Fitted Size Distributions According to Specific Gravity Fraction

Homer City, Feed No. 1

Specific Gravity	Characteristic Size, d(mm)	Dispersion Parameter, n
FLOAT - 1.25	0.3	0.52
1.25 - 1.27	2.2	0.77
1.27 - 1.30	3.3	0.81
1.30 - 1.32	4.5	0.79
1.32 - 1.35	10.6	0.72
1.35 - 1.40	38.0	0.56
1.40 - 1.45	26.5	0.71
1.45 - 1.50	21.1	0.71
1.50 - 1.60	44.1	0.64
1.60 - 1.70	46.1	0.73
1.70 - 1.80	68.6	0.72
1.80 - SINK	78.8	0.61

(1) Rosin-Rammler distribution:

$$F(x) = 1 - \exp(-(x/d)^n),$$

where F(x) denotes the proportion of the distribution less than size x, with d and n denoting the characteristic size and dispersion parameter, respectively.

An examination of this table shows an irregular increase in the characteristic size associated with increasing specific-gravity fractions. Smooth behavior across the levels of specific gravity would appear to require a characteristic size somewhat smaller than the 38.0 mm size shown at a specific gravity of 1.4. Characteristic sizes somewhat larger than 26.5 and 21.1 mm would also be indicated for specific gravities of 1.45 and 1.50.

The dispersion parameters are somewhat uniform over most specific gravities. The lowest values of the dispersion parameter are seen to be associated with the smallest characteristic size 0.3 mm, and with the possibly aberrant 38 mm size at a specific gravity of 1.40. The arithmetic mean and standard deviation of the values of dispersion parameters are found to be 0.69 and 0.09, respectively, with a coefficient of variation of 13 percent.

Figure 2 shows an overlay of all 12 Rosin-Rammler distributions represented on ln-ln vs. ln scales. Uniform behavior from one specific gravity to the next would be indicated on such a plot if, for example, all lines were coincident, or if a uniform rotation occurred about the point of concurrence at (0,0). In fact, however, no such uniform behavior is exhibited. This is due, in part at least, to the non-uniformities previously mentioned for the n and d parameters associated with specific gravities 1.40, 1.45, and 1.50 as shown in Table 1.

Figure 3 shows a plot of log d^n versus specific gravity. This plot suggests that a discontinunity has occurred that

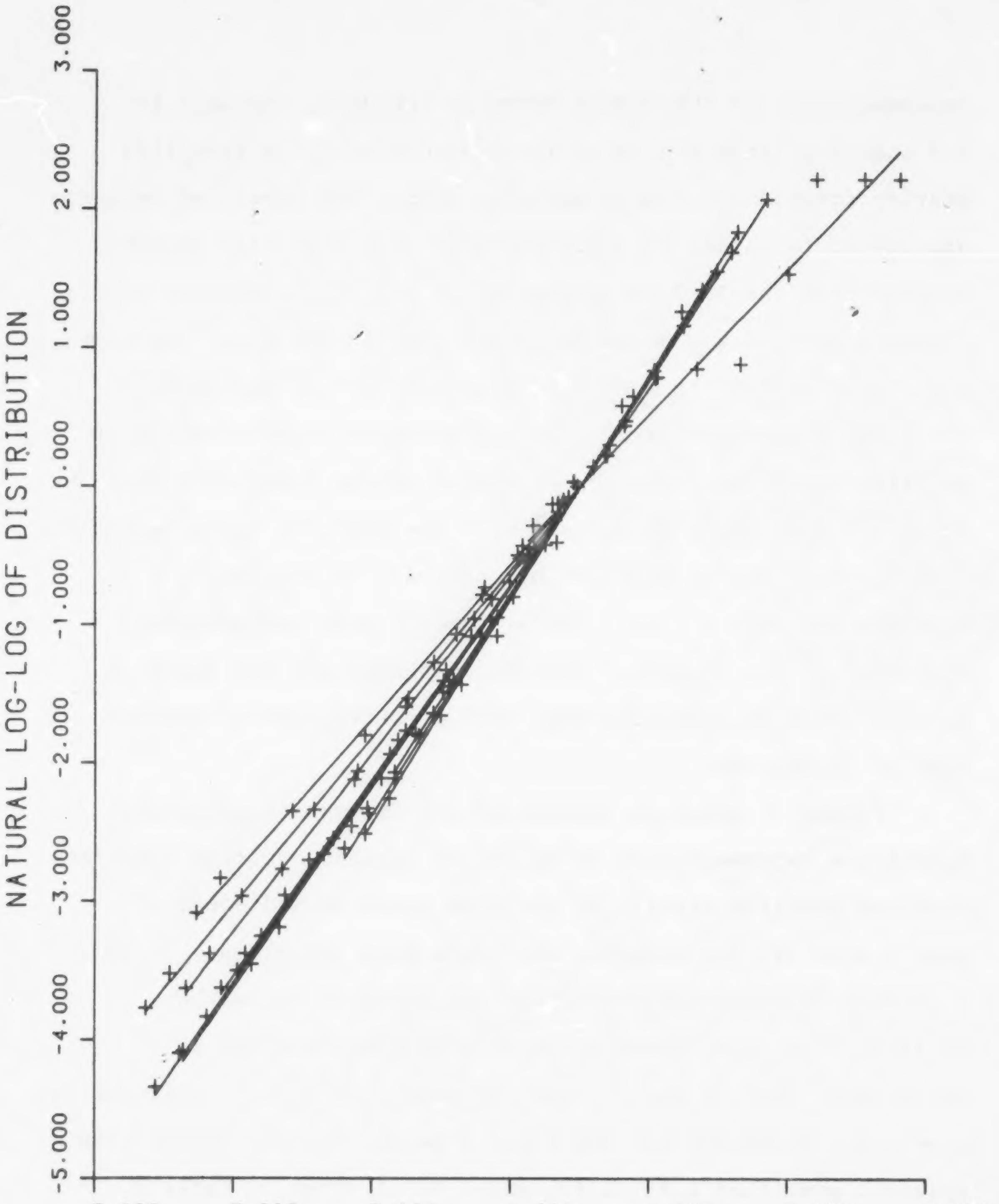


FIGURE 2. Superimposed Rosin-Rammler Representations of Weight Percent, According to Size Fraction, for 12 Specific Gravity Fractions for Homer City, Feed No. 1, Washability Data

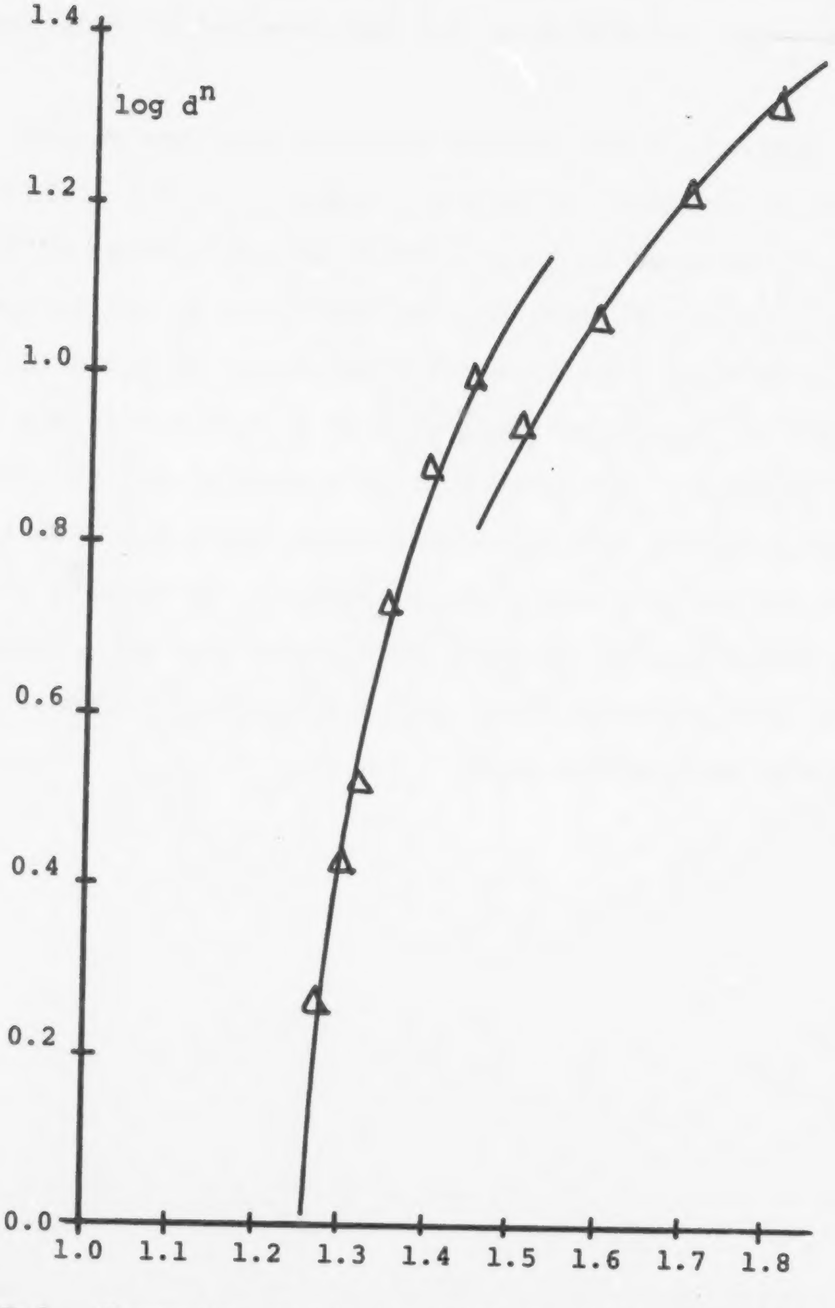


FIGURE 3. Parameter Variation with Specific Gravity

separates the last 4 specific gravity fractions from the earlier fractions. Other examinations of these results are also being made to account, if possible, for the observed non-uniform behavior.

In summary, these results indicate that the weight fractions for washability data for Homer City coal (Feed No. 1) are well-represented by Rosin-Rammler distributions, with a separate distribution used to represent each of the 12 specific gravity fractions. The dispersion parameter is found to lie in the 2 standard deviation interval 0.69 ± 0.18 across all specific gravity fractions. The characteristic size parameter shows some irregularity across the specific gravity fractions. This behavior is currently under study as part of the general effort to obtain a Rosin-Rammler surface that can be used as a general basis for interpolating among coarse washability data to obtain more refined washability data.

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DEWATERING AND DRYING OF FINE COAL: EQUIPMENT PERFORMANCE AND COSTS

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ABSTRACT

The physical cleaning of fine coal for pyrite removal results in product and refuse streams with high moisture contents. The added costs for dewatering, for transportation, and for environmental controls have been generally recognized, but they have not previously been systematically documented such that they may be compared with the benefits achieved by coal cleaning.

The Environmental Protection Agency therefore directed Versar, Inc., to fully define the costs of fine coal dewatering, handling and transportation; with the objective of enabling the cost evaluation under any reasonable combination of fine coal product stream size consist and initial water content, fine coal dewatering and drying unit process alternatives, and fine coal handling and transportation alternatives.

First, the unit processes and equipment for fine coal dewatering were systematically studied. For each, the performance in terms of water removal capability; the useful range in terms of feed size consist and feed moisture content; the required size as a function of throughput; and the equipment costs as a function of size; were all defined. Examples are presented in this paper.

Also presented are the results of an early case study in which the costs to a preparation plant operator for alternative dewatering and drying schemes are compared to the economic benefits achieved by shipping drier coal to an electric utility coal user.

Introduction

Historically, physical coal cleaning for ash removal was directed at coarse coal fractions. Fine coal, 3/8-inch x 28 mesh material, was not generally beneficiated but was directly blended with the cleaned coarse coal. The very fine fraction, 28 mesh x 0 material, was discarded as refuse.

In contrast, physical coal cleaning for sulfur removal necessitates crushing to sufficient fineness to liberate the pyrite. The higher fractions of fine coal resulting from continuous mining techniques and from crushing for pyrite liberation are processed by a variety of separation techniques, and constitute a major portion of the clean coal product. Both the higher surface moisture content of fine coal fractions and the higher percentages of fine coal in the clean coal product result in added costs for dewatering and drying, for transportation, and for environmental controls.

As part of a Coal Cleaning Technology Development program being conducted for the Environmental Protection Agency under Contract 68-02-2199; EPA directed Versar, Inc., to perform a cost evaluation for fine coal dewatering and drying under any reasonable combination of fine coal product stream size consist and initial water content, fine coal dewatering and drying unit process alternatives, and fine coal handling and transportation alternatives. Although these added costs have been generally recognized, they have not previously been systematically documented such that they may be compared with the environmental and economic benefits achieved by coal cleaning.

Dewatering and Drying Equipment Performance

Table 1 lists several major categories of equipment useful in the dewatering and drying of fine coal. The ranges of moisture content reductions shown in Table 1 dictate the place each type of device has in an overall dewatering and drying process. The first stages of dewatering a fine coal slurry with 80 to 95 per cent water might be followed by devices which can further dry the coal. The selection of equipment is further guided by the size range of the coal -a centrifuge might be chosen for a 3/8-inch top size coal, whereas a vacuum filter would be selected if the top size were 28 mesh. Several categories of equipment result in comparatively low solids recoveries, and generally should be followed by some effluent treatment scheme.

Based upon extensive data gathered for specific items of equipment, dewatering and drying performance curves were generated to cover more generalized equipment types. Figure 1, for Screens, and Figure 2, for Centrifuges, are two examples. The performance curves are useful in predicting the moisture content of the product from each device, while the use of the device is constrained by feed moisture content and feed size consist requirements discussed above.

Also based upon the specific-equipment data base were generalized sizing curves. An example, for hydrocyclones, is shown in Figure 3. This family of curves is useful in specifying the nominal equipment size required for a given throughput.

Dewatering and Drying Equipment Costs

Generalized purchase cost curves for fine coal dewatering and drying equipment were also prepared from the specific-equipment data base. The purchase cost is displayed in Figure 4, as an example (for hydrocyclones), as a function of the equipment size. The combined use of the sizing curves and the purchase cost curves enables a purchase cost to be estimated for a given device and for a given throughput.

Plant capital costs (which include equipment, buildings and structures, piping, electrical, erection, engineering, and contractors fees) were estimated as 3.2 times the dewatering equipment capital costs. Although individual items of equipment might have shorter useful lifetimes, the annual capital recovery costs were calculated on the basis of a 15-year plant amortization, and on the basis of a 10 per cent interest rate.

Operating and Maintenance Costs for Dewatering and Drying

Direct operating costs (including direct labor, electrical power, heat, materials, and supplies) for each type of device are listed in Table 2. These are costs per ton of dry coal throughput, except for refuse ponding and disposal costs, which are per ton of wet refuse, and except for the direct thermal dryer operating costs, which are per ton of water evaporated. Also in Table 2 are annual maintenance costs and annual indirect operating costs (taxes, insurance, supervisory, and administrative costs), which are estimated as a percentage of the total plant capital costs.

Additional Cost Elements

Transportation costs are based upon the total weight shipped, including moisture. In addition, the coal cleaning plant operator pays approximately 74 cents for the Pension and Benefit Trust Fund for each ton (including moisture) of coal shipped.

The coal user, e.g., an electric utility, is assumed to contract for net heating value. For the purposes of analyzing dewatering and drying operations only, a constant heating value (of 13,650 Btu per pound) of dry coal is assumed, since no appreciable change in coal composition results from these operations. However, any associated moisture in the coal received is, for the purposes of this study, penalized by the requirement for sufficient additional coal to vaporize this moisture. This additional coal penalty is the total cost of such coal through mining and the entire cleaning plant beneficiation process including separation, dewatering and drying, and refuse disposal; and is assumed to be $20 per ton (dry basis). In addition, a power-plant pulverization cost of 60 cents per wet ton is assessed to the additional coal requirement.

Outline of Case Study

The first case study conducted to compare the costs of alternative dewatering and drying schemes with the economic benefits of shipping dried coal is presented in this paper. A 580 MW electric utility in Montgomery County, Maryland has a net coal heating value requirement of 35.5 x 10^{12} Btu per year. It is supplied with cleaned coal from the Pittsburgh coal bed in Marion County, West Virginia, with a heating value (dry basis) of 13,650 Btu per pound. Rail transportation for the 245-mile distance is at a cost of $6.23 per ton (including moisture).

The coal preparation plant has a nominal raw coal throughput of 500 tons per hour (tph), and operates 13 hours per day for 254 days per year. The 6-inch top size coal is screened, yielding 250 tph of 6 x 3/8 coal which is washed and dewatered, and 200 tph cleaned coarse coal are recovered at 3.4 per cent surface moisture (equivalent to 207.2 wet tons per hour). The fine coal circuit has a feed of 250 tph of 3/8 x 0 coal. The heavy media cyclone and froth flotation circuit has two clean coal streams: 160 tph of 3/8 x 28 M coal at 12 per cent surface moisture, and a slurry of 35 tph of 28 M x 0 with 69.9 per cent water. Each of these two fine coal streams is then dewatered and dried in alternate ways, yielding a fine coal product with different moisture contents. The fine coal product is then blended with the cleaned coarse coal for shipment to the consumer.

Based upon the capital and operating costs presented earlier for fine coal dewatering and drying, the annual costs for the several alternatives were evaluated for the nominal 500 tph plant. These annual costs were then adjusted to account for the differing quantities of coal which must be shipped (depending upon the final moisture content) to supply the utility's net heat requirement.

Dewatering and Drying Alternatives

Seven alternative schemes for fine coal dewatering and drying were defined in this case study. Case O is the baseline case in which no dewatering or drying is performed on the fine coal. By definition, the cleaning plant capital, operating, and maintenance costs attributable to fine coal dewatering and drying are zero for Case O. However, the transportation and power-plant penalty costs would be highest for Case O, since the largest quantity of water is also shipped. For Cases A through F, where water is removed from the fine coal, the capital, operating, and maintenance costs of water removal are greater than zero. For these cases, the transportation and power-plant penalties are less than for Case O, and the economic benefits of water removal are evaluated as the differential from Case O penalties.

Case A is straightforward mechanical dewatering (which is also performed in Cases B-E): the 3/8 x 28 M stream is centrifuged, and the 28 M x 0 stream is filtered. More moisture removal is performed in Cases B and C by drying the filter cake of 28 M x 0 coal: in Case B, with an indirect heat exchanger; and in Case C, this filter cake is dried in a direct thermal dryer. The objective in Cases D and E is not further moisture removal than Case A, but it is the recovery of fine coal from the centrate in the 3/8 x 28 M circuit. In Case D, the centrate is processed in a hydrocyclone for slimes removal, with the fine coal fraction then filtered, and with the filter cake added to the fine coal product. In Case E, slimes removal prior to vacuum filtration is performed by a flotation cell rather than by a hydrocyclone.

Case F is intended to perform additional moisture removal without solids loss from a centrifuge. In this case, the 3/8 x 28 M stream is not dewatered in a centrifuge, but instead is directly combined with the filter cake from the dewatered (in a vacuum filter) 28 M x 0 coal. The combined 3/8 x 0 coal is then dried in a direct thermal dryer.

The nominal coal and moisture quantities for each of the seven cases are listed in Table 3. These quantities are consistent with the 500 tph feed rate to the coal cleaning plant, and are the basis of the dewatering and drying cost calculations. These quantities (and subsequently, the costs) are adjusted for the power-plant penalty of vaporizing moisture, on the basis of 3.2×10^6 Btu needed per ton of water; and for the solids losses in the dewatering and drying operations. The adjustment calculations are shown in Table 4.

Costs and Benefits for Dewatering and Drying Alternatives

Using the unit process capital and operating cost data, annual costs for fine coal dewatering and drying, for each of the seven alternatives, were calculated. These are listed in Table 5.

Table 5 also shows the total annual costs associated with delivering the clean coal product to the utility consumer. In addition to the trust fund and transportation costs, the utility pulverization costs and the utility penalty for contained moisture are included. These costs include the economic penalties for not dewatering and drying the fine coal. Conversely, the total benefits from fine coal dewatering and drying are the cost savings compared to the baseline case (Case O), where no moisture removal occurred. The net annual benefit is defined as the total benefit less the total processing costs.

Table 6 is a summary of the costs and benefits of the fine coal dewatering and drying alternatives, expressed per dry ton of fine coal product. It must be emphasized that the operations listed for the alternatives were performed on partial fine coal streams, so that the costs do not represent cummulative costs for sequential operations on the same stream.

Conclusions for this Case Study

For this case study, limited to one user/producer scenario, all of the fine coal dewatering and drying alternatives show significant benefits compared to the baseline case of no dewatering. It is instructive to compare the net benefits to those of Case A ($3.10 per ton), which is limited to mechanical dewatering processes. Case B, in which the filter cake is dried in an indirect heat exchanger, is only marginally more attractive. Case C, where a direct thermal dryer is used, is significantly less attractive than Case A. In Cases D and E, the recovery of solids from the centrate appears attractive, reflecting lower refuse disposal costs as well as recovered product values. The use of a thermal dryer in Case F to avoid centrate solids losses is apparently competitive with Cases D and E.

Conclusions for Other Case Studies

The conclusions reached for other case studies may well be quite different from those above. It is apparent from Table 5 that of all the additional cost elements from which the benefits are derived, transportation costs are dominant. To assess the impact of other user/producer distances, two additional scenarios were examined. In one extreme scenario, the utility is adjacent to the mine and to the coal preparation plant, so that transportation costs are zero. In the second extreme scenario representing much longer-distance hauling, transportation costs were assumed to be three times those of Table 5.

The results of these two scenarios are summarized in Table 7, along with those of the first case study. With much higher transportation costs, alternatives B and F (which utilize thermal drying) begin to appear more attractive. Conversely, with no transportation costs, the thermal drying alternatives show negative benefits: e.g., these processing costs are excessive.

Based upon the few scenarios shown in Table 7, several preliminary overall conclusions may be drawn. First, the net benefits achieved in Case A, by straightforward mechanical dewatering, are not lower by large amounts than those achieved by more complex (and more capital-intensive) dewatering and drying schemes. Second, the net benefits achieved in Cases D and E, by recovery of centrate solids, appear attractive and are achieved with only moderate increases in capital investment as compared to Case A.

The early results presented in this paper were achieved without testing other parameters for their effects. One such parameter which could change the conclusions is the amortization time for capital investment: a significantly shorter period than the 15 years assumed in the early case study needs evaluation. Another parameter not yet evaluated is a change in the basic coal preparation plant flow sheet, with different coarse coal/fine coal ratios and with different moisture contents of the wet fine coal streams prior to dewatering.

TABLE 1
FINE COAL DEWATERING AND DRYING EQUIPMENT

EQUIPMENT TYPE	FEED MOISTURE, %	PRODUCT MOISTURE, %	TYPICAL SOLIDS RECOVERY, %
VIBRATING SCREEN	40-90	12-16	80
STATIONARY SCREEN	60-90	40-50	80
CENTRIFUGE	60-80	12-20	90
HYDROCYCLONE*	85-90	40-60	50
FLOTATION CELL*	95	70	90
VACUUM FILTER	65-75	20-30	99+
STATIC THICKENER	85-95	60-70	99+
DIRECT THERMAL DRIER	12-15	6-7.5	99+
INDIRECT THERMAL DRIER	20-25	8-14	99+

*USEFUL FOR SLIMES REMOVAL PRIOR TO FILTRATION.

TABLE 2
OPERATING AND MAINTENANCE COSTS

DIRECT OPERATING COSTS:

DISC VACUUM FILTER	$0.70/TON DRY COAL
DRUM VACUUM FILTER	0.80/TON DRY COAL
STATIC THICKENER	0.35/TON DRY COAL
SCREEN & SOLID BOWL CENTRIFUGE	0.22/TON DRY COAL
HYDRAULIC CYCLONE	0.04/TON DRY COAL
FLOTATION CELL	0.20/TON DRY COAL
DEWATERING SCREEN	0.01/TON DRY COAL
INDIRECT HEAT EXCHANGER	0.28/TON DRY COAL
DIRECT THERMAL DRIER	4.00/TON WATER REMOVED
REFUSE PONDING & DISPOSAL	1.00/TON TOTAL REFUSE

INDIRECT OPERATING COSTS AND MAINTENANCE (PCT. OF INSTALLED CAPITAL COSTS)

TAXES	2.0%
INSURANCE	1.0%
SUPERVISORY AND ADMINISTRATIVE COSTS	1.5%
MAINTENANCE COSTS	5.0%
TOTAL	9.5%

TABLE 3
COAL AND MOISTURE QUANTITIES
Basis: 500 tph Raw Coal Feed

Case	0	A	B	C	D	E	F
Clean Coarse Coal (6 x 3/8):							
Dry tph	200	200	200	200	200	200	200
Moisture, gpm	28.5	28.5	28.5	28.5	28.5	28.5	28.5
Moisture, pct.	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Wet tph	207.2	207.2	207.2	207.2	207.2	207.2	207.2
Clean Fine Coal (3/8 x 0):							
Dry tph	195	187	186.6	186.6	191.3	194.2	193.0
Moisture, gpm	412	91.6	60.8	54.4	94.8	101.2	49.2
Moisture, pct.	34.6	10.95	7.5	6.8	11.0	11.5	6.0
Wet tph	298.1	210	201.8	200.2	215.1	219.6	205.3
Total Clean Coal Product (6 x 0):							
Dry tph	395	387	386.6	386.6	391.3	394.2	393.0
Moisture, gpm	440.5	120.1	89.3	82.9	123.3	129.7	77.7
Moisture, pct.	21.8	7.2	5.5	5.1	7.3	7.6	4.7
Wet tph	505.3	417.2	409.0	407.4	422.3	426.8	412.5
Refuse (After thickening):							
Dry tph	0	8	8	8	3.7	0.8	0
Wet tph (@ 30% solids)	0	26.7	26.7	26.7	12.3	2.7	0
Solids Loss to Atmosphere:							
Dry tph	0	0	0.4	0.4	0	0	2.0

TABLE 4

ADJUSTMENT OF COAL AND MOISTURE QUANTITIES

Basis: 3,302 Operating Hours per Year
13,650 Btu per Pound (Dry Basis) Heating Value
3.2 x 10^6 Btu per Ton Water Power Plant Penalty
35.5 x 10^{12} Btu per Year Net Power Plant Requirement

Case	0	A	B	C	D	E	F
Unadjusted Quantities:							
Wet TPH of Product	505.3	417.1	409.0	407.4	422.3	426.8	412.5
Wet 10^6 TPY of Product	1.6685	1.3776	1.3505	1.3452	1.3944	1.4093	1.3621
Dry TPH of Product	395	387	386.6	386.6	391.3	394.2	393.0
Dry 10^6 TPY of Product	1.3043	1.2779	1.2766	1.2766	1.2921	1.3016	1.2977
Gross 10^{12} Btu/Year	35.61	34.89	34.85	34.85	35.27	35.53	35.43
Moisture, TPH	110.3	30.2	22.4	20.8	31.0	32.6	19.5
Moisture, 10^3 TPY	364.2	99.7	74.0	68.7	102.4	107.6	64.4
Moisture Penalty, 10^{12} Btu/Year	1.17	0.32	0.24	0.22	0.33	0.34	0.21
Net 10^{12} Btu/Year	34.44	34.57	34.61	34.63	34.94	35.19	35.22
Adjustment Factor = Req'd Btu/Net Btu	1.0308	1.0269	1.0257	1.0251	1.0159	1.0088	1.0080
Adjusted Quantities:							
Wet 10^6 TPY of Product	1.7199	1.4147	1.3852	1.3790	1.4166	1.4217	1.3730
Dry 10^6 TPY of Product	1.3445	1.3123	1.3094	1.3086	1.3126	1.3131	1.3081
Additional Required Quantities:							
Wet 10^3 TPY of Product	51.4	37.1	34.7	33.8	22.2	12.4	10.9
Dry 10^3 TPY of Product	40.2	34.4	32.8	32.0	20.5	11.5	10.4

TABLE 5
ANNUAL COSTS AND BENEFITS
(THOUSAND DOLLARS)

CASE	0	A	B	C	D	E	F
EQUIPMENT PURCHASE COSTS	0	316	616	1116	425	392	992
PLANT INVESTMENT COST	0	1011	1971	3571	1361	1253	3174
ANNUAL CAPITAL RECOVERY COST	0	130	254	460	176	162	409
ANNUAL DIRECT OPERATING COST	0	197	229	320	210	221	357
ANNUAL INDIRECT O&M COST	0	96	187	339	129	119	302
ANNUAL REFUSE DISPOSAL COST	0	88	88	88	41	9	0
TOTAL ANNUAL PROCESSING COST	0	511	758	1207	556	511	1068
ANNUAL TRUST FUND COST	1273	1047	1025	1020	1048	1052	1016
ANNUAL TRANSPORTATION COST	10715	8814	8630	8591	8825	8857	8554
ANNUAL UTILITY PULVERIZ. COST	1032	849	831	827	850	853	824
ANNUAL UTILITY MOISTURE COST	804	688	656	640	410	230	208
TOTAL ANNUAL ADDITIONAL COST	13824	11398	11142	11078	11133	10992	10602
TOTAL ANNUAL BENEFIT*	0	2426	2682	2746	2691	2832	3222
NET ANNUAL BENEFIT	0	1915	1924	1539	2135	2321	2154

*BENEFIT IS DEFINED AS COST SAVING COMPARED TO BASE CASE 0.

TABLE 6

COSTS AND BENEFITS PER DRY TON OF FINE COAL PRODUCT

NOTE: OPERATIONS LISTED WERE PERFORMED ON PARTIAL STREAMS

CASE	FINE COAL DEWATERING & DRYING OPERATIONS	COST PER TON	BENEFIT PER TON	NET BENEFIT PER TON
0	NONE	$ 0.00	$ 0.00	$ 0.00
A	CENTRIFUGATION, FILTRATION	0.83	3.93	3.10
B	CENT., FILT., IND. HT. EXCH.	1.23	4.35	3.12
C	CENT., FILT., DIRECT THERM. DRYER	1.96	4.46	2.50
D	CENT., FILT., HYDROCYCLONE, FILT.	0.88	4.26	3.38
E	CENT., FILT., FLOTATION, FILT.	0.80	4.42	3.62
F	FILT., DIRECT THERMAL DRYER	1.68	5.06	3.38

TABLE 7

SENSITIVITY OF BENEFITS TO TRANSPORTATION COSTS

Case	Fine Coal Dewatering & Drying Operations	Net Benefit Per Ton of Fine Coal Product		
		$6.23/Ton	$18.69/Ton	$0.00/Ton
0	None	$0.00	$0.00	$0.00
A	Centrifugation, Filtration	3.10	9.27	0.02
B	Cent., Filt., Ind. Ht. Exch.	3.12	9.89	-0.26
C	Cent., Filt., Direct Therm. Dryer	2.50	9.39	-0.95
D	Cent., Filt., Hydrocyclone, Filt.	3.38	9.36	0.39
E	Cent., Filt., Flotation, Filt.	3.62	9.42	0.72
F	Filt., Direct Thermal Dryer	3.38	10.17	-0.01

FIGURE 1

SCREEN PERFORMANCE FOR FINE COAL DEWATERING

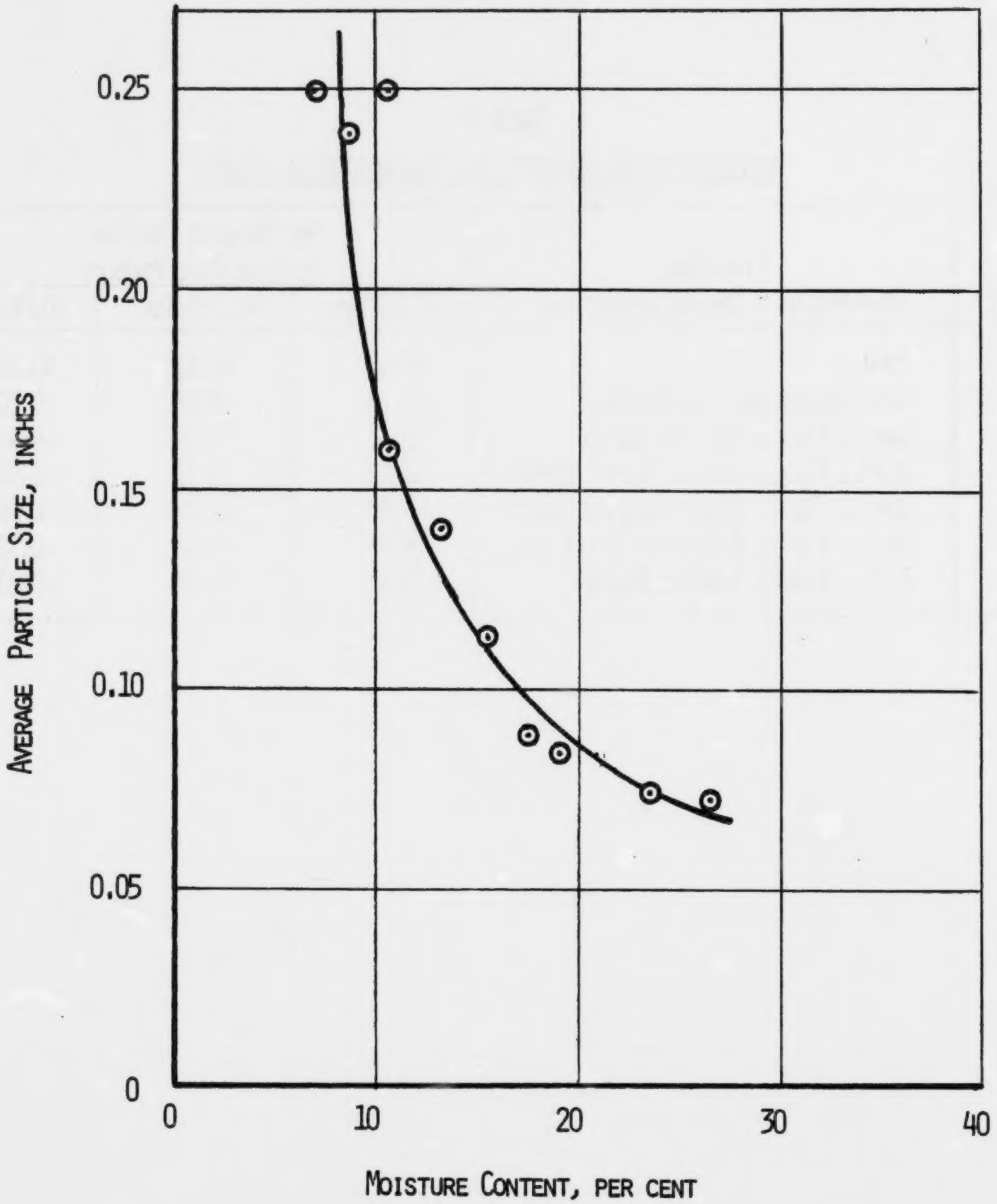


FIGURE 2

CENTRIFUGE PERFORMANCE FOR FINE COAL DEWATERING

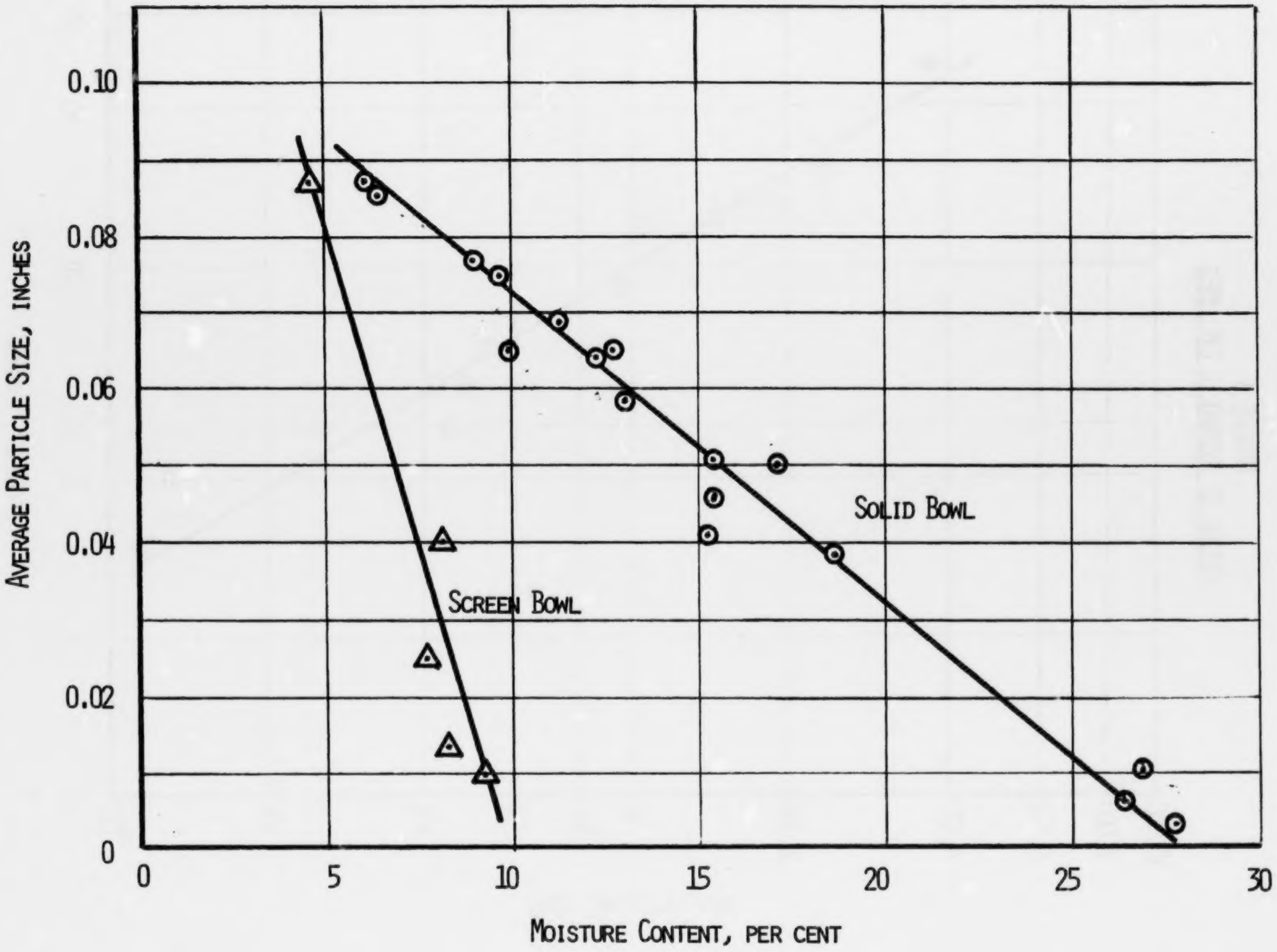


FIGURE 3
SIZING OF HYDRAULIC CYCLONES

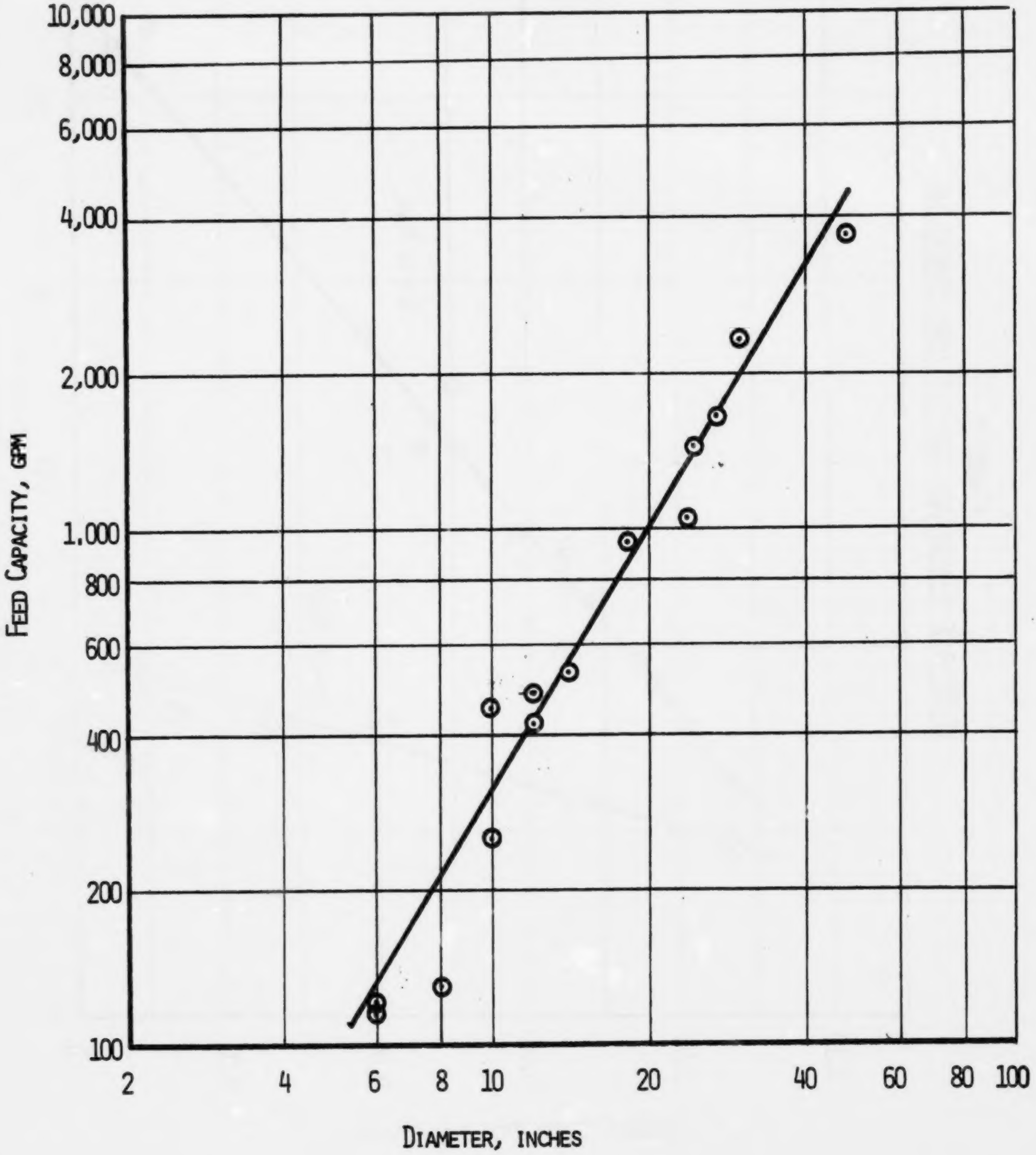
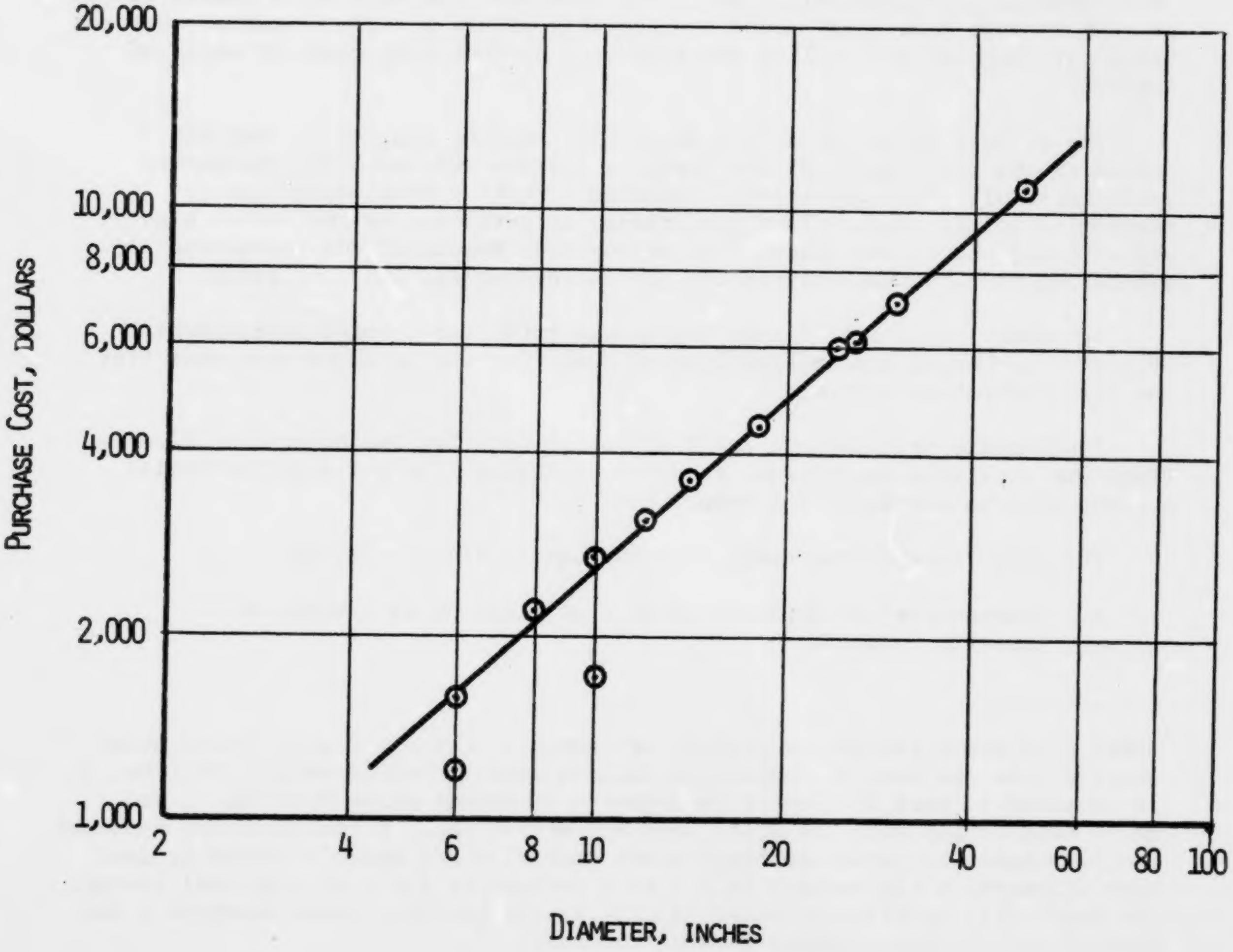


FIGURE 4
PURCHASE COST OF HYDRAULIC CYCLONES



HOMER CITY COAL CLEANING DEMONSTRATION, TEST, AND TECHNOLOGY EVALUATION PROGRAM

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ABSTRACT

A 1,200-ton-per-hour coal cleaning facility at Homer City Station[1] is being intensively tested as a means of evaluating the impacts of coal cleaning environmentally, economically, and operationally. The full-scale beneficiation of coal through this heavy media process will afford a ready comparison between front-end cleaning and on-line gas scrubbing as competing means of emission control.

The primary objective of the Homer City testing program is that of assessing the performance of the cleaning systems and comparing the actual performance with that originally projected. Further evaluations are not meaningful unless proper plant performance is assured. Several other high priority objectives are those of assessing the impacts of the integrated generating plant on the environment, boiler operation, and cost areas.

Secondary tests will assess the energy efficiency, total environmental effluent discharge, and availability of coal cleaning in comparison with flue gas desulfurization systems.

Preliminary calculations based on design data for the Homer City Cleaning Plant and available operational data from existing flue gas desulfurization systems will be tabulated for comparison.

The objectives of the Homer City evaluation are as follows.

A. Demonstrate the application of coal cleaning as a means of emission control.

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[1] Homer City power generation complex is composed of three fossil-fueled units located near the town of Indiana in Indiana County, Pennsylvania. Unit No. 3 is required to meet New Source Performance Standards while Units No. 1 and No. 2 must comply with the State Implementation Plan. A coal cleaning approach has been taken to clean captively mixed coal with 2.8 percent sulfur to meet both standards while wasting only 5 to 6 percent of the available coal energy. The Homer City facility is owned jointly by the New York State Electric & Gas Company and the Pennsylvania Electric Company.

B. Assess the performance and operating characteristics of several types of heavy media equipment now available and in operation at Homer City with suggestions for improved design or operation.

C. Evaluate the full costs of coal cleaning as an emission control--environmentally, economically, and in terms of total system energy consumption.

D. Introduce those segments of present coal cleaning applications which require additional research or development work.

E. Assess the "secondary" effects of coal cleaning in boiler operation, electrostatic precipitator performance, solid and liquid effluent control, and total energy use.

F. Employ advance systems of control and measurement to monitor the output of the coal cleaning process and permit a high degree of quality control.

G. Utilize developing systems of mathematical process modeling to aid in coal procurement, process control, and operation diagnosis.

The Homer City Coal Cleaning Plant is the first demonstration of coal cleaning to meet Federal New Source Performance Standards for a full-sized fossil fuel unit. The adaptation of coal cleaning at Homer City has attracted a growing interest from both regulatory and research-oriented concerns. Following is a brief description of the Homer City facility, and of the series of interactive tests and evaluations which have been planned to satisfy the industry's need for information.

The Homer City Generating Complex was originally constructed as two, 600 megawatt coal fired units in 1969, operating primarily on fuel which is mined at two captive mines on site. This generating station, located in Indiana County, Pennsylvania, is equally share-owned by the Pennsylvania Electric Company (Penelec), and the New York State Electric and Gas Corporation (NYSEG). The station as originally operated could not achieve compliance with the Pennsylvania SO_2 regulations which were imposed in March of 1972, using run-of-mine coal. When a new 650 megawatt addition was proposed for the site, an assessment of available sulfur oxide control techniques was begun with all three units in mind.

The new 650 megawatt Unit #3 proposed for the station at Homer City, as well as the existing units, was in need of some method of sulfur removal in order to comply with the Federal New Source Performance Standards

(NSPS) and the State Implementation Plan (SIP) respectively. These factors weighed heavily in favor of the development of an integrated, multi-level coal cleaning system for the site. Several systems were evaluated after a detailed washability of the captive reserves was developed. The design which was selected utilized a broad spectrum of conventionally applied coal cleaning equipment, working to its best advantage on a preprocessed feedstock. This integrated system of coal processing came to be known as the Multi-Stream Coal Cleaning System or MCCS.

Coal cleaning was chosen as the only means of SO_2 control for the Homer City site after a comparative evaluation of flue gas scrubbing and MCCS coal cleaning projected some very tangible economic benefits which could result from the successful operation of the highly specialized MCCS. The cost comparison for both alternatives at Homer City is shown as Figure 1.

The Heyl and Patterson Company (H&P) proposed to construct the developed MCCS system on the Homer City site as two independently operating 600 ton per hour (raw coal) circuits. Their final design recognized all of the limitations and capabilities of existing coal processing equipment, while extending those capabilities through further refinement of conventionally used systems. The key element in producing one-third of the coal output at a quality sufficient to meet Federal NSPS is the H&P heavy media cyclone operating at an effective separating gravity of 1.30 grams per milliliter on specially sized and classified feedstock from the run-of-mine coal. The balance of plant output will be recovered at a quality to meet the Pennsylvania State Implementation Plan levels of 4.0 lbs. of SO_2 per million BTU's of boiler heat input. The recovery efficiency of this integrated approach to coal cleaning has been projected to be almost 95 percent. That is, approximately 95 percent of the heating value of the raw coal will be recovered as fuel for the Homer City units.

Heyl and Patterson has recently completed construction of one, 600 TPH circuit to provide these specialized coals for the operation of all three Homer City generating units. Problems have been experienced in operating the new plant, complicated by simultaneous construction work on the second 600 TPH (raw coal) circuit, and the recent United Mine Workers strike. Start-up is proceeding in an orderly manner, with increased levels of plant operating capacity being met each week. Some coal has been produced by the plant which meets the NSPS, but quantities have been limited to date.

Simultaneously with the construction of the Homer City Coal Cleaning Plant, a multi-faceted plan was drawn up by the Homer City Owners to test and evaluate the concept of emission control by coal cleaning in general and the performance of the Homer City cleaning circuits in particular. The original objectives for the test series were amended when both the United States Environmental Protection Agency and the Electric Power Research Institute expressed strong interest in the conceptual evaluation. The test plan which has evolved will meet the program objectives of all of the participating agencies, while moving to develop improvements in coal cleaning technology applicable to the Homer City and most conventionally constructed cleaning plants.

The most complex series of tests will break each one of the eight size/gravity circuits out of the plant and evaluate each against its design criteria in terms of feedstock characteristics, product characteristics, circuit throughput, and cost of operation. This series of tests serves as a foundation for many of the subsequent determinations by assuring the participants that the plant is operating near design conditions and producing clean coals of acceptable quality for further work. These first test series will also help to optimize the performance of the individual circuits in the plant and further characterize equipment performance when each type operates with a closely controlled size and quality classified feed as designed. The MCCS will also be tested to insure compliance with equipment guarantees from the manufacturer and steady state of operation at full plant capacity.

In the course of these tests, ancillary plant equipment will also be tested to assure that environmental safeguards are operating correctly. The Homer City MCCS was designed as a zero discharge facility with respect to liquid effluents. This zero discharge concept, and the performance of low head particulate scrubbers which control emissions from the four thermal coal dryers, will be thoroughly evaluated to gauge applicability on future coal cleaning installations. There is, of course, a strong interaction between the operation of the plant circuits at full capacity and the successful use of these control devices.

In drawing the program for detailed circuit testing, it was found that systems for accurately measuring the flow rates and for obtaining a representative sample of a three-phase coal, magnitite, and water slurry flowing in an unsteady state were not well defined. The need for accuracy in the circuit tests led to the adaptation of two initial test series to try to select the best system of flow measurement and flow sampling. In our test plan, these are called "methodology development" and "slurry sampling systems." Some evaluations of slurry samples have been done by Versar, Incorporated, under a plan of their development and a further series of trials will be made when large size slurry samplers are installed in the operating plant.

Inquiries by the test committees have revealed that several systems of flow measurement using either sonic, magnetic, nuclear absorption, or some combination of these methods are available and have been applied to slurry systems. Several of the most promising types of devices are being purchased for comparative evaluation in the Homer City circuits. A specialized flow loop is now envisioned to evaluate a number of these devices side by side; with the ability to divert the stream over a weir arrangement for a control flow indication. Some of these flow measuring devices are portable, to easily monitor a number of streams in succession to aid in balancing flows to parallel equipment. Early use of these flow sensors has indicated that the division of slurry flows in an equipment circuit is not an easy job, but should be approached with some specialized design work for a successful split.

Because of the MCCS's strong reliance on the heavy media cyclone to perform coal beneficiation, a program is now in process at the U. S. Bureau of Mines facility in Bruceton, Pennsylvania, to optimize heavy media cyclone performance by finding the best combination of operating parameters. The operating criteria being assessed are media to coal ratio, cyclone operating pressure, inlet and outlet orifice sizes, and magnetite size characteristics. A series of eighty-one separate runs are being made with a 6-inch pilot scale cyclone at the Bureau, which will gauge the effect of varying operation on the gravimetric separation of a tightly controlled feedstock. Data developed at the Bureau will be compared with similar data collected during the MCCS tests to find the correct scaling factor for the 6-inch Bureau cyclone installation.

Heavy media cyclones used at the Homer City coal cleaning installation are designed to perform a reasonably sharp gravimetric separation on coals down to 100 mesh in size. The cyclone loop at the Bureau of Mines will be instrumental in defining the performance of fine coal separation and in assessing the detrimental effects of quantities of misplaced fine coal on the sharpness of separation. This pilot scale operating loop affords to the Homer City Owners a means of quickly determining the causes of operating effects observed in the course of operating the full-size plant cyclones. This program also stands alone to help optimize cyclone design and operation in future coal cleaning systems on an industry-wide basis.

In designing the Homer City MCCS, questions arose concerning the instruments that measure and control the many streams within the coal washing plant. A program has been initiated to assess and suggest improvements to existing specific gravity controls on the heavy media circuits to limit the variation in media gravity during operation. This control becomes extremely important when operating at low media gravities where a small variation can drastically affect the quantity or quality recovery of deep cleaned coal products. This task is tied to the assessment of test instrumentation discussed earlier, because an accurate determination of specific gravity is an important component of the flow calculation.

The design of the MCCS will be fully successful only when tight operational control over the circuits allows the plant to be tailored to the varying feed coals quickly. Control instrument work at the U. S. Bureau of Mines has led Penelec to believe that tight control is only possible if care is used in operating and maintaining the monitoring equipment. These early tests have indicated that proper measurement accuracy is available to maintain the slurry within acceptable limits if calibrations are made frequently and in the proper manner.

An additional instrument development program will demonstrate and test a non-destructive means of instantaneous coal analysis to enable the MCCS plant performance to be closely monitored without analytical delays. The method of analysis employed is related to neutron activation in the mineral matter constituents of the coal. A summing of these elemental quantities is the basis for a determination of total ash, for which a BTU value can be assigned if the BTU/ash relationship for the mine has been previously defined. For the Homer City coals, the BTU/ash characteristics are well established by almost ten years of operation. Moisture content may also be determined by using this nuclear analysis, but specialty chute designs are necessary to optimize the irradiation while eliminating background scatter from other nearby materials. Successful use of several on-line instruments will enable much better control of the complex circuits by making plant operators aware when various coals are introduced into the process.

The original decision of the Owners to use coal cleaning in lieu of FGD was made based on an economic analysis. Because of the projected nature of data use, both for evolving FGD and for MCCS cleaning, a subsequent and more thorough economic analysis must be made to compare these alternative systems using actual operating data. This comparison will use information concerning the cost of sulfur removal for both alternative methods, and will ease the burden of future comparisons within the industry. Further analytical developments may pave the way for designing a combination of the two methods to improve availability and cost effectiveness over singly employed systems. An economic design of the future could use coal cleaning to do an 80 or so percent removal job at low cost, while using partial scrubbing with by-pass gas reheat to achieve an overall 90 percent to 95 percent removal with good availability and less disposal problems.

A possible economic benefit which was not considered in the adaptation of coal cleaning technology at Homer City is that the use of extremely low ash and sulfur fuel may improve the performance of the downstream combustion cycle to provide additional economies. The effects of burning extremely low sulfur coal in the #3 boiler will be tested by the boiler manufacturer, Babcock and Wilcox, using a run-of-mine grade of coal initially, and comparing this to a similar series of tests made using deep cleaned coal later on. Longer term economic analysis will be made by comparing operating and maintenance costs of Homer City #3 against those of other Penelec operated units. Theoretically, the low ash fuel should permit a high boiler efficiency by reducing heat losses in the ash. Combustion should be more complete, and slag concentration on the heat transfer surfaces should be minimized. Ash erosion and slag fall damage in the steam generator should be noticeably reduced.

Future coal burning facilities using compliant low sulfur and ash cleaned coal will have to struggle with the particulate control problem as Homer City has. The Homer City Owners selected an extremely overdesigned electrostatic precipitator to clean the low resistivity dust which is expected to be produced. One facet of the test work here is the characterization of emitted dust from the control ESP's, including a particle size analysis. A second trial will assess the magnitude of precipitator rapping losses currently thought to be a major cause of dust carry-over. Testing here will fully characterize ESP performance on deep cleaned coal ash, and should enable a less costly design to be used for future units.

Environmental evaluations will be made within the area of influence of the Homer City site to assess the total impact of coal cleaning on the background. Several initial tests have been made by Battelle Memorial Institute, and these will be compared with data taken after the cleaning system is in full operation. Data from the long-term operation of Penelec's ambient air monitoring system will also be factored into this evaluation. Homer City's total environmental impact should be less detrimental than that of a non-regenerative scrubbing unit due to the more limited quantities of solid and liquid effluents discharged.

Coal cleaning at Homer City could be improved by pretreating the plant feedstock to separate the mineral matter from the coal by selective comminution or crushing. Certain methods of coal crushing may preferentially liberate the minerally rich veins from the bulk of the carbonaceous material. Once broken free they can be easily separated by the heavy media cyclones, or other gravimetric separating systems.

Manufacturers of various types of crushing systems have been contacted and a test series has been devised to measure the effect of coal crushing methods in the liberation of mineral matter. This test series will also assess the developing technique of chemical treatment as a means of comminution to free coal's mineral matter constituents. A system which works best on the captive Homer City coals may not be the optimum method for coals from other geographic locations.

Detailed in-seam sampling by the U. S. Geological Survey within the two Homer City reserves has shown that mineral matter tends to be very concentrated in layers within the coal seams. True optimization of the coal cleaning operation should thus begin in the mine at the working face and proceed to work on segregated coal fractions from that point. This approach is impractical today, but further developments in mining equipment and techniques could someday afford the opportunity to take advantage of this important first step in coal cleaning.

A cost consideration in the operation of a heavy media cleaning plant is the loss of magnitite to the product coals and refuse. At Homer City, the Owners have done preliminary studies which indicate that media-grade magnitite should be available from fly ash collected in Units #1 and #2 electrostatic precipitators as a product from combusting iron pyrite in coal. The recovery and use of this resource at the cleaning plant could result in a substantial savings in cleaning plant operating costs. Further improvement in the separation efficiency of the heavy media systems could also be a benefit if the reprocessed magnitite were specially sized, or if larger quantities of low cost material were available to make-up the otherwise uneconomical losses resulting from the use of an extremely fine grade magnetite. The experiments mentioned earlier at the Bureau of Mines should provide a guide to the most efficient magnetite grade for separating at low gravity.

The final program which comprises part of the Homer City development effort is the further improvement of a mathematical model to describe operations of the coal cleaning plant circuits. Battelle Memorial Institute has recently issued an advanced coal cleaning system computer model under the name, "CPSM-4," which was extensively tested on the Homer City plant configuration. Use of this and other modeling techniques can permit more accurate optimization of a coal cleaning plant design if the characteristics of the feedstock are known. By replicating runs of the simulator and changing the proposed equipment configuration mathematically, a much improved facility design can result which will take maximum advantage of the feed coal characterisitics to produce the most optimum recovery rates. This work had previously been done as a laborious process which restricted the number of possible trials and thus the degree of optimization.

At Homer City, CPSM-4 will have an important place in frequently predicting the plant performance to give readouts of existing product quality around each of the circuit cleaning equipment types. This modeling concept, when tied to a series of on-line analyzers, can afford a new dimension of control in the operation of a coal cleaning facility. As the feedstock undergoes a short term change, either in source or size consist, the appropriate data inputs to an advanced model could alert the plant operator to control changes necessary to meet recovery objectives in one or more of the product streams. A fully automated preparation plant of the future will use modeling as an instantaneous control device, just as the downstream power plants have integrated and automated the control and monitoring functions. The next step in improving Battelle's mathematical model will be the addition of cost information to the matrix, which allows the user to both qualitatively and economically evaluate the coal cleaning concept for any projected use at any given time. Other phases of the Homer City test program will gather information for input and development of a cost refined version of Battelle's "CPSM-4," which can find industry-wide application.

This total proposed program of testing and technology evaluation at the Homer City Generating Complex will provide operational, economic, environmental, and product end use data which will demonstrate the applicability of coal cleaning to the utility industry, and highlight further the necessary improvements in that technology for use in future, advanced cleaning facilities.

FIGURE 1

HOMER CITY GENERATING STATION

ALTERNATIVE SO_2 CONTROL STRATEGIES

COST COMPARISON - COAL PREPARATION vs. FGD

Capital Investment for SO_2 Control - $ Millions	FGD	MCCS
Coal Preparation Facilities		
Original Plant (for use with FGD)	18	18
MCCS Addition	0	32
FGD	59	0
Sub-Total	77	50

Annual Revenue Requirements for SO_2 Control - $ Millions	FGD	MCCS
Fixed Charges	11.6	7.5
Operating and Maintenance Expenses		
FGD	10.6	0
Coal Preparation	3.2	7.6
Sub-Total	25.4	15.1

NOTES:

1. Capital Costs include provision for AFDC, escalation and 10% contingency (MCCS Contingency - 15%).
2. MCCS Capital includes provision for separate plant coal handling system (6.0) and R&D support (1.0) plus associated AFDC, escalation and contingency.

COMPUTER CONTROL OF COAL PREPARATION PLANTS

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ABSTRACT

This paper discusses previous unsuccessful attempts by computer companies to control coal preparation plant operations, while outlining the problems involved. Questions as to the purpose and advantages of computerized plants are posed and answered. What can be done at present in computer applications in coal preparation plants? What will be possible in the future? Past, present and future concepts are illustrated with reference to plants in which Concol has played the major role. Three aspects of computerization of coal preparation plants are discussed, namely process control, operations control, and management. The required combination of hardware and software are outlined in general with some reference to economics and process design.

1. INTRODUCTION

Raw coal from mining operations requires upgrading prior to utilization, to ensure a cleaner environment and for the twin economic reasons of profitability and energy conservation. To satisfy these requirements, a coal preparation plant must operate efficiently, safely, with a minimum of "downtime" and produce the maximum yield of clean coal at a consistent specified quality. Experience with manually operated plants has shown an average utilization factor of only 80%, a safety record that has only improved with legislation, and significant variations in yield and quality of clean coal products with consequential losses of energy.

What can the computer do to improve operation efficiency, plant utilization, maintenance and overall profitability thereby improving energy recovery?

2. THE OBJECTIVES AND SCOPE OF COMPUTER CONTROL

The computer can keep watch, or stand guard over the process continually, and it can self-diagnose faults within itself and diagnose faults on items of plant contained within the process system. In conventional plants about 85% of the downtime is used in fault diagnosis and only 15% in actually replacing faulty units. The computer will ensure that the plant remains in an operable condition, being controlled to a preferred set of parameters. When an unacceptable deviation from these parameters occurs the computer will either,

(a) correct the deviation checking it for "normality", and/or
(b) inform the central control room operator, and/or
(c) shut down the necessary plant items as the particular case requires, and control the consequential effects on the process, or
(d) shut down the plant completely.

Computer control of coal preparation plants covers three activities, the major activity being plant contro. The other two activities are ancillary to plant control and depending upon economic, and/or market considerations and can be included or excluded, as required. For a complete system all three types are necessary, these are:

(a) plant control,
(b) process evaluation,
(c) management.

2.1 Plant Control

The plant control computer has evolved as a means of controlling all functions necessary for the efficient and safe operation of the plant. The first consideration is maximum reliability. Since computer reliability decreases as the number of peripheral devices, for example keyboards, display screens, magnetic disc drives, etc., increase, the system must minimize the number of such devices on the plant control machine. The main areas of plant control can be identified as follows:

(a) sequence control of motors,
(b) sequence control of automatic valves,
(c) analogue control of plant process variables.

Operation of the control system should be basically simple and logical, and require a minimum of specialized knowledge. Priority is given to the ease of maintenance and fault diagnosis. The basic system should operate on the principle that the plant, whatever its function, should always be in an operable state. In order to minimize plant downtime, the following attributes are required in the system:

(a) maximum reliability and minimum physical components,
(b) rapid tracing of the causes of failures and subsequent replacement of faulty units,
(c) minimum training for operating personnel,
(d) flexibility to accommodate changes in, or extensions to the existing plant.

A major aspect of computer control of coal preparation plants is the provision of the necessary measuring and sensing devices required for data input and the accuracy and reliability of the measurements and signals. This is important, since a computer is only as good as the data it is given.

The sensing carried out on all drives would be as follows:

(a) Starter Ready - this would include any desired hard sequence, any automatic or manual switching, main power available at the starter, and control power available.

(b) Electrical Fault - this would include earth leakage, overload and main fuse failure.

(c) Auxiliary Contact - this would be a physical electrical contact mounted directly to the motor main, or control contactor.

(d) Proving Switch - this would be a sensing implant that the drive., i.e., pump, cell, etc. is carrying out its required duty.

As an example, a pump would have a flow switch as far towards the end of its effect as possible,--say, the overflow from the cyclone would be a check that the main cyclone feed pump is operational.

This function is most important, for example, it is not merely sufficient to monitor that a pump is in fact rotating--the line may be blocked, a valve may have failed to open, a pipe may have in fact burst. It is, therefore, of particular importance that the chain of events stemming from pump operation be monitored as far down the line as pssible.

(e) Motor Current - this is an analogue signal derived directly from the motor starter current transformer.

The above items are generally the minimum data requirements for each drive, but others are sometimes either necessary or requested by the customer, such as:

(f) Speed Switches - would normally be a two-level speed sensing device. This device when mounted on a belt conveyor for example, would be on a non-driven member of the belt, such as the taildrum, and would be set up such that if the taildrum ran, say at 40% or less of normal operating speed, the device would detect this and notify the computer to stop feed to the conveyor. A second speed level, at say, 90% of full speed, could warn the operator of a possible fault, giving time and opportunity for correcting action. (Such as the reduction of plant feed and rate.)

(g) Insulation Testing - is an independent routine for the computer. When the plant is in a stationary condition and the main drive power removed from the motor control centers, the computer would in turn test each drive for its insulation value. Set points of the minimum allowable insulation value would be retained in the memory and any error would be recorded and an alarm activated.

(h) Analog Measurements - such as density of separation, tank levels, feed rate, etc. for the successful control of coal preparation plant rely on the accuracy and the repeatability of these measurements. These anlog measurements are now well proven, but some field measurements still require improvement or development, e.g., ash and sulfur coal, solids concentration in froth flotation feed, pulp etc.

Sensing of items such as valve open/close status, and blocked chute probes, will be required by the computer for plant control.

2.2 Process Evaluation

Test work performed on samples of raw coal provides washability information which is used to predict set points in a particular coal washing process, for example, densities of separation. The plant will maintain a fixed operating condition, unless a change is requested. The comparison of washability data with actual plant performance assumes accurate data until excessive deviations occur. When these deviations are noticeable, renewed test work will be performed for more current washability data and the prediction of new set points. The coal wash plant flowsheet model is set up from the washability data, so that calculated outputs are fed to the plant control function. The latter function also receives information on anomalies, such that the model can be altered when necessary.

The reliability of the plant algorithm is determined by the compatability of input washability data in relation to the actual washability of the coal flowing through the plant at a given time. When dense media processes apply, an ongoing measure of predicted error can be made through online determinations of ash contents and specific gravities of media. There is no need to carry out specific gravities of media. There is no need to carry out performance tests after those associated with commissioning since performance can be continually monitored. Process evaluation by computer is not new, but its application as an integral part of the plant control is unique in coal preparation.

The washability input consists simply of the theoretical ash: separating gravity (Dp) relationship for a given coal being cleaned. Online ash monitors determine clean coal quality, and the theoretical cutpoint Dpt corresponding to that ash content, is compared with the actual cutpoint Dpa. EP's as calculated from prediction programs for dense medium processes are related to the actual and theoretical cutpoints by the function.

$$Ep = f(Dpt-Dpa)$$

Where:

Ep = probable error

Dpt = theoretical cutpoint for actual ash obtained

Dpa = actual cutpoint

Serious deviations from expected EP's would mean either:

(a) inefficient operation of the plant, or
(b) a significant change in washability characteristics of the coal

2.3 Management Data

The management data function of the modern advanced control system can be the basis for all planned and breakdown maintenance functions for a plant. This can obviously be greatly beneficial for the organization of the preventative maintenance that will be required on a plant throughout its operating life. A brief listing of some management functions available on modern control systems are:

1. Maintenance Data Accumulation, i.e.:
    - (a) number of operational hours for each device
    - (b) number of operations of each device
    - (c) prediction of device or component failure from historical data
2. Maintenance Instructions.
3. Maintenance Schedules and Inventory Control.
4. Mimic Displays to Facilitate Plant Operation.
5. Process Optimization by:
    - (a) memorizing and using washability data for all seams being washed using Mayer curves, and
    - (b) maximizing feed rate by ensuring that the current load limitation factor is identified

and fully loaded.

6. Stockpile Blending to Control the Consistency of Ash and Sulfur Contents of the Final Blend.
7. Shift Logs and Reports of All Aspects of Plant Operation That Have Been Monitored.

The management computer used to carry out the above listed functions would differ from the plant control computer only by the addition of bulk storage devices such as magnetic discs, extra color visual display units and hard copy printers. The interrelationship of these units is illustrated in the flow diagram.

3. COMPUTER CONTROL DEVELOPMENT

Early ventures made into the automation and control of coal preparation plants were only partially successful, and the conclusion from these early experiments showed a need for:

(a) Robust and reliable equipment, both for control and monitoring functions. Control equipment available at the time was fragile and needed to be protected from shock loadings, dust, moisture, and extremes of temperature, i.e., all of those environmental factors that may be found on almost every coal preparation plant.

(b) Cooperation between design, computer, and electrical engineers in the application of these advanced techniques to coal preparation. It became apparent that for successful application of advanced control techniques, the selection, design, and construction of the plant must be carried out before the event rather than afterward.

The three projects described below incorporated changes in control systems which allowed development to the present level of capability.

3.1 The Fording Project

The first successful application of some of these techniques to coal preparation was on a plant in Canada in the period 1968-1971. This plant was designed to produce metallurgical coal for export and to process this coal at 1,000 tons per hour, through a twin-stream plant; each stream having large coal heavy medium, small coal heavy medium, and fine coal sections. Alternate methods of achieving desired objectives in control were evaluated and costed. Computers for control purposes were examined, but were found to be expensive, fragile, and extremely sensitive to environmental changes. As a result of this the basic control system choice was between pneumatics and electronics.

Pneumatics were cheap, established, and readily available, with a considerable amount of technical backup. Electronics were found to be in the region of four times as expensive as pneumatics and not in general use. However, when specifications and operating life were considered, the electronic units were far superior. Consequently electronic elements with an orthodox but comprehensive central control desk was the chosen control system.

Two major areas of investigation involved in the design exercise were:

(a) transmission elements
(b) final control elements

Transmission problems arose when such equipment was applied to coal preparation plants, the elements being fastened to equipment for which they were never designed. Nuclear density gauges were used and once interfacing had been completed between in-plant monitors and processing devices, they proved most reliable. Final process control elements gave rise to problems in two main areas. One was the control of diverter head boxes, known as "Elephant's Trunk" (ETS) systems. The actuation of the ETS systems was finally carred out by means of pneumatic cylinders operating against a spring.

The second main problem area was that of valve actuation, which was difficult to solve at the time, because actuated valves were normally used only for remote manual control, and not automatic control involving the use of feed-back.

It became apparent that even though this level of control was successful, more work had to be carried out on ways of:

(a) reducing the amount of control equipment,
(b) finding quicker methods of isolating problems within the equipment, and
(c) obtaining more reliable equipment

Achieving these objectives would then reduce the number of service personnel required, and also lessen the necessity for such personnel to have specialized knowledge hence an indication towards later philosophy in that it is desirable to achieve self-diagnosing, high reliability systems capable of being operated and maintained by unqualified personnel.

The project was however, successful and the client was satisfied with the result in terms of efficiency, consistency of products, safety, minimum downtime and running costs.

3.2 The Thurcroft Project

In 1973, the British coal industry was expressing considerable interest in the use of computers for proposed new coal preparation plants.

During September 1974, the authors became involved in the design and construction of the Thurcroft coal preparation plant as chief executives of the main plant contractor and of instrumentation and process control subcontractor.

The plant comprises coarse coal heavy medium bath (3 product), small coal heavy medium cyclones (primary and secondary) and froth flotation for the production of very high quality metallurgical coal with the intermediate S.G. range material as steam coal.

Control hardware for the plant comprises Modicon I/O (input/output) cabinets, three Modicon processors (programable logic controllers [P.L.]) and a variety of measuring and monitoring apparatus. Digital aspects of control are handled by the P.L.C. units, analog items such as S.G.'s and levels are handled by Foxboro. Spec. 2000 equipment interfaced with the Modicon units as necessary for alarms etc.

The system utilizes basic programing techniques that can be loaded via paper or magnetic tape into the main processor memory.

A visual display unit is provided with the control system for fault finding diagnosis.

Reprograming with this system via a standard terminal keyboard is simple and quick.

For control purposes, the plant (including raw coal handling and product outloading) is split into ten groups on the control desk.

Each group is complete with "start", "hold", and "stop", buttons, and each drive group within the group is represented by its description, control reference number and three Light Emitting Diodes (L.E.D.'s) as below:

Green - drive ready to start
Amber - electrical stoppage--external, i.e., stop botton, blocked chute probe, pull wire
Red - electrical fault--internal, i.e., overload fuses or thermistor

When a group start is initiated, the pre-start alarm times out, and then thr group hold light pulses at one second intervals, starting each drive sequentially within the group. When the group is running, the flashing hold light is extinguished and the group stop light illuminated.

Run-up time for the total plant is 6-8 minutes, and the plant may be started or stopped (excluding Group 1) by the use of three push bottons:

Auto Start
Auto Hold, and
Auto Stop

The desk is complete with an L.E.D. illuminated "dark" type mimic diagram, i.e., the mimic is dark both when the plant is stationary and operating. Illumination only occurring when a drive is in a starting condition or when the process has determined a drive to be the cause of a stoppage.

The drive L.E.D.'s maintained above are red. Green L.E.D.'s are continuously lit to give valve position indication.

A closed circuit TV system is installed, comprising two fixed cameras and four remotely operated units with zoom, pan, and tilt facility to observe when required, important transfer points, feed launders, etc.

Analog measurements include suspension gravities, tank levels, feed and product tonnages, filter bowl levels, filter bowl levels, filter vacuum, and bunker levels.

Digital measurements include speed switches, tilt switchees, float switches, blocked chute probes, capacitance probes, door positions, and all automatic valve limits.

The plant was brought "on-stream" in November 1976, and the comissioning and achievement of commercial operation required only three (3) days! Due to the nature and mode of control employed, efficiency of separation and consistency of products are excellent and the plant has, after two years of operation, a first-class safety record.

Although the plant does not encompass any management data functions, it is fair to say that due to the various warning modes incorporated in the control system, some potentially serious incidents to proprietary equipment have been avoided. In terms of running costs, the plant has upturned much conventional thinking, and has to date proved to be cheaper to operate than a conventional jig plant. This in itself being something of a revelation.

The user has been extremely satisfied by the operation of this plant at all levels, and indeed many people world-wide have visited the plant and as a result of these visits many favorable reports have been received.

The plant requires five men for operation, including the control room operator. Without the control system, ten men would have been required to give what would be without a doubt, an inferior level of control.

This plant has a control system that is a measure of design, process, and instrument capability at the time it was built. It has also provided an indication of the way forward in terms of development in design, instrumentation and process control.

3.3. The South Kirkby Project

This is a 1,000 ton per hour twin-stream plant comprising large coal heavy medium, small coal heavy medium, and a common fines recovery circuit.

The client's requirements were for a comprehensive management data function in addition to the normal plant control and process evaluation modes.

Programable logic controllers were again considered for this project because of their proven reliability. However, because of the comparatively large size of the plant, this would have required thirteen control processors, plus three communication processors, to give the same degree of control as given by the three units employed at Thurcroft. From a reliability standpoint, therefore, it can be appreciated that even though the previous application gave very high reliability, the overall reliability of sixteen units needed on the new project would have been lower. After further investigation, it was found that high reliability could still be maintained by using a much larger single computer, if the configuration was kept in its simplest form. The plant control machine then consisted of computer, memory, color VDU for operator output, a standard typewriter keyboard for the operator to input to the computer, and finally a printer, for hard copies, alarms and logs, etc. It should be noted, therefore, that the machine used had no magnetic disc drives and other such high density information storage devices which are generally the cause of computer failure.

Because one computer carries out the work that would have been performed by sixteen programable logic controllers, and because, this single machine has no bulk storage memory system, the software has to be capable of running in the computer's own, comparatively small, high speed, random access memory.

It was necessary to handle three thousand five hundred items of digital information, and seven hundred and fifty items of analogue information, and in addition provide a comprehensive management data system. The final configuration, therefore, was the selection of two PDP11/34 computers, one operating as a plant control machine, the other as a management data processor as shown on the control system flow diagram.

To provide the comprehensive management data required, it was necessary to equip the standard machine with visual display units, disc drives, etc., to give the machine the large memory capacity required for this duty.

However, if the main plant control machine fails then a mechanical disconnection of the main processor and a reconnection of the management data machine, disconnected from its peripheral devices, will allow normal running of the process plant. Management data services would be suspended until the failed machine could be serviced.

A failure of the management data machine, although suspending management functions, would in no way interfere with plant operation.

It will be noted that the two machines are not in fact electronically connected together as installed, in order to prevent the possibility of interference or argument between the two machines in the event of failure of either unit. Such electrical connection could in fact lead to serious consequences on the plant in the event of machine failure. The connection between a given machine and plant control is thus effected by a multi-pin plug.

4. PROBLEM AREAS

We have attempted in this paper to show why advanced control systems are necessary, in modern coal preparation, and how we translated this need into an operating concept. We hope we have shown with specific reference to three plants, with which we have been involved, how such systems have evolved, and been applied in a practical and effective manner, compatible with our overall objective in the optimization of benefits from the preparation of coal.

It is however, also necessary to mention some problem areas encountered with the application of computer techniques to coal preparation. A plant operator is capable of value judgments or in computer terms, analog. The computer itself is incapable of making such decisions and relies solely on the interpretation of digital or "yes"/"no" information for its actions. Consequently, instead of one analog measurement, several digital signals may be required and a problem commonly encountered is that of transducer reliability.

Solid state technology produces reliable sensing elements--though if and when these elements fail, we are left with something of a problem, i.e., does one merely tell the computer to ignore a faulty transducer, or does one keep several million dollars worth of machinery idle, while awaiting the procurement and installation of a transducer costing a few dollars? If the first policy is adopted and plant management is ineffective, the situation can arise where, over a period of time, many transducers are rendered useless and yet the plant will continue to run. This state is unsafe from an operator's view, and no warning can be given of certain conditions arising on a plant which may lead to expensive damage to equipment, with consequential loss of revenue and excessive downtime. The second policy is unattractive financially, in terms of lost revenue and downtime.

We have given this problem considerable thought and have arrived at a conclusion which, answers the problem effectively, provided that adequate control is maintained by plant management. Memory access is achieved, either by (a) direct access to the memory units via the visual display units, or (b) altering hardwired sequence in the I/O cabinets.

Thus, particular transducers can be disabled directly from the keyboard. It is however, of the utmost importance that accurate records of such temporary alterations are fully documented and presented immediately to plant management, so that the necessary rectification/replacement of the unit can be done at the earliest opportunity, and transducer monitoring levels maintained on all items throughout the plant. This system has in fact worked well. The management data system will perform this recording function as part of its duties, though the responsibility for implementation of the work will rest with the plant management. The management computer will produce a record of all disablements on every shift log until restoration takes place.

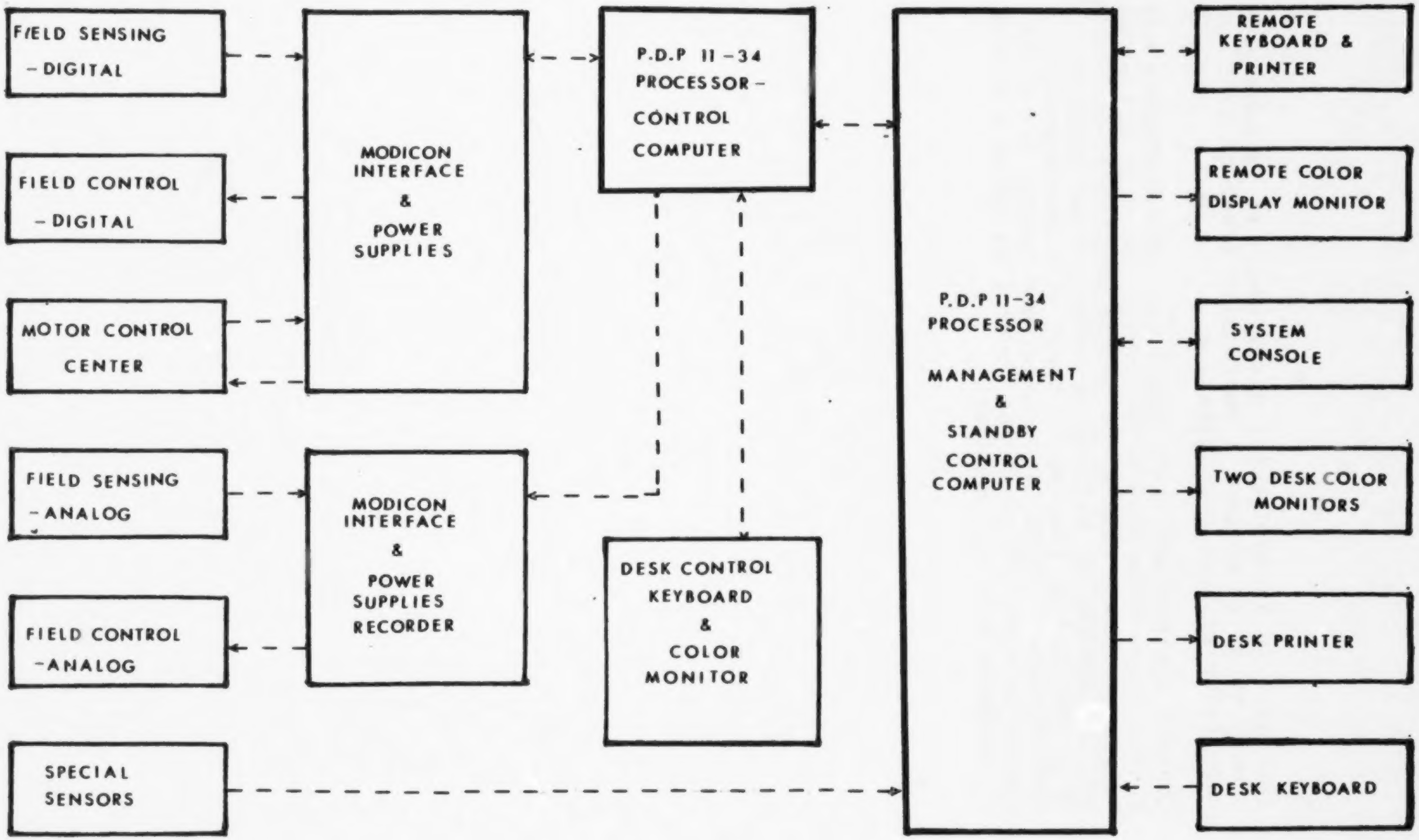
5. FUTURE SITUATION

Developments in solid state technology are outstripping those in almost every other field to such an extent that by the time a control system has been conceived, designed and installed, it is in terms of hardware, virtually outdated.

Future developments in mining will see the complete mine control system, and a central processor being responsible for both the extraction, handling, preparation, and outloading of coal from a particular mine. This total concept mining should result in increasing cost effectiveness of the unit and the ability of that unit to be efficient, and closely tied to market trends and fluctuations.

Technology is now available to produce control systems considerably in advance of those discussed in this paper. However, it is important that economics be closely evaluated when considering the implementation of these systems. In an industrial environment it is generally uneconomical to achieve a particular level of technical excellence without justification.

Control systems and their practical implementation must at all times be viewed objectively. We must not be led by people simply wishing to market computers, or conversely, not be hindered by stilted or conventional thinking. It is a question of keeping in touch with developments, technological trends, and costs, and having the right system in terms of plant and control to offer a client to optimize his requirements.


FIELD SENSING
- DIGITAL
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MOTOR CONTROL
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FIELD SENSING
- ANALOG
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- ANALOG
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MODICON
INTERFACE
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RECORDER
P.D.P 11 - 34
PROCESSOR -
CONTROL
COMPUTER
DESK CONTROL
KEYBOARD
&
COLOR
MONITOR
P.D.P 11-34
PROCESSOR
MANAGEMENT
&
STANDBY
CONTROL
COMPUTER
REMOTE
KEYBOARD &
PRINTER
REMOTE COLOR
DISPLAY MONITOR
SYSTEM
CONSOLE
TWO DESK COLOR
MONITORS
DESK PRINTER
DESK KEYBOARD

FLOW DIAGRAM OF A COMPLETE COMPUTER CONTROL SYSTEM

PHYSICAL AND PHYSICOCHEMICAL REMOVAL OF SULFUR FROM COAL

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ABSTRACT

A coal preparation plant for evaluation of existing state of the art processes and for developing new processes has been constructed on the Iowa State University campus. The conventional portion of the plant can be operated in the 20 to 70 TPH range while the advanced processes are in the hundreds of pounds per hour range. The installation was funded by the State of Iowa and the Department of Energy and is operated through the Energy and Mineral Resources Research Institute.

Processing equipment in the plant circuit includes a heavy media separator, concentration tables, hydrocyclones, froth flotation cells, oil agglomeration equipment, dewatering screens, cyclones and filters, crushers, ball mills, pelletizers, conveyors, and thickeners to provide a closed circuit.

Coal samples ranging from 500 to 8000 tons have been processed using coals with sulfur contents of 2.5 to 8.75 percent. Using the conventional coarse coal processing circuit, sulfur reductions average 35 percent with ash reduction averaging 45 percent. The equipment for advanced fine coal beneficiation has been installed and a heavy media cyclone circuit and an extruder are being added.

A description of the processes with data obtained to date is presented as well as an overview of related coal research projects.

I. INTRODUCTION

The development of improved coal cleaning methods has been underway at Iowa State University since 1974 when the Iowa Coal Project was established with funds provided by the Iowa Legislature and administered by the Energy and Mineral Resources Research Institute (EMRRI). The primary goals of the effort center on:

1) Demonstration of existing coal cleaning techniques in optimum circuit configurations so as to permit reasonable estimates of their cost and effectiveness.
2) Development and demonstration of new coal cleaning techniques to be utilized in support of existing technologies and to minimize the environmental impact of coal cleaning and utilization.
3) Development of supporting programs in coal characterization and analytical technology for major, minor and trace element determinations and to better understand the nature of coal and its associated minerals such that rational cleaning processes can be developed.

When this research effort was launched, a dual attack was made on high sulfur coal. One approach was the construction of a coal preparation plant capable of demonstrating the performance of selected existing methods for cleaning high sulfur coal which would allow for an assessment of the economics of the processes. A logical selection process chose as the first methods selected for demonstration and evaluation those commercial methods which seemed to have the highest benefit/cost ratio. However, these were gravity separation methods which only removed coarse refuse. Since most high sulfur coal also contains finely disseminated pyrites, a second approach was to screen a number of promising but largely undeveloped methods for removing impurities, to select several methods for further development, and to proceed in developing these methods. The separation methods selected for development include those based on froth flotation, oil agglomeration, hydrocyclones, heavy media cyclones, and high gradient magnetic separation. All of these methods are designed for cleaning fine size coal which is the size that must be cleaned if finely disseminated pyrites are to be liberated and removed and physical coal cleaning is to become effective in meeting some of the various existing and proposed air quality standards. The development of these methods has been uneven since funds were limited. While methods based on froth flotation and oil agglomeration have received extensive bench scale testing and laboratory development leading to the recent installation of a 500-1000 lb/per hour process demonstration unit at the Ames coal research preparation plant, the other methods have received limited attention. However, since hydrocyclones (installed June, 1978) and heavy media cyclones (to be installed Spring 1979) do not lend themselves to small scale systems, these devices have been or are being incorporated into the Ames coal preparation plant and will be evaluated on a demonstration or semi-industrial plant scale.

To improve the separation of coal and pyrites achieved by either froth flotation or oil agglomeration, research has focused on chemical pretreatment of coal fines to enhance the difference in surface properties of the two components. In addition, various combinations of gravity separation, froth flotation, oil agglomeration, and comminution methods have been tested on a bench or demonstration scale to determine what extent these methods complement each other.

II. IOWA STATE UNIVERSITY DEMONSTRATION MINE NO. 1

Before describing our preparation plant, I would like to mention another aspect of our project - the source of some of the nations finest 8% sulfur coal.

A demonstration mine was established on a 40 acre site to determine the potential for reclaiming surfaced mined land for row crop production. Topsoil, nonacid overburden and shale were stockpiled separately during the mining operation and returned in their original layers and re-contoured into bench terraces. (Figure 1)

Originally the site was suitable only for pasture but now contains approximately 25 acres of land suitable for row-crop farming. Studies are being continued to produce optimal conditions for agricultural production.

III. AMES RESEARCH COAL PREPARATION PLANT

A coal preparation plant has been built on the campus of Iowa State University to demonstrate various methods of cleaning coal on a larger scale.

A building to house the plant (Figure 2) and the first section of the plant to clean coarse and medium size coal were completed in 1976. This section included a primary variable speed crusher, heavy media separator, wet concentration table, size separation and dewatering screens, and materials handling equipment. Hydrocyclones for cleaning fine size coal and disc filters for dewatering fines were added in June, 1978; heavy media cyclones for cleaning medium size coal will be added in 1979. All of this equipment is of a semi-industrial scale (approximately 70 TPH) and was funded by the State of Iowa. Pilot plant circuitry to demonstrate our modified froth flotation and oil agglomeration methods of beneficiating fine size coal was installed in 1978 using funds provided by the Fossil Energy Division of the U. S. Department of Energy. A pelletizing circuit was also included at that time. (Figure 3)

The present plant utilizes three processes to separate coal from its impurities. The coal is received as mined and is sized in an impact mill. A vibrating grizzly allows the minus 1½ inch to bypass the crusher. The crushed coal is held in a surge hopper and metered onto the raw coal conveyor. A separating screen pre-wets the coal and separates the plus 3/8" material from the minus 3/8" material.

The 1½" x 3/8" coal is then fed to a cone-shaped heavy media vessel. The clean coal is swept around the surface of the cone and flows over a weir to a scalping screen where the media is returned to the vessel. The coal proceeds across a vibrating screen where any remaining media is washed from the coal and is delivered to the clean coal conveyor and onto a stockpile.

The refuse which has sunk to the bottom of the cone is pumped to a scalping screen to remove the media and then across a vibrating screen where it is rinsed and ultimately delivered to a refuse stockpile.

The 3/8" x 0 coal is delivered from the separating screen to a double-deck concentration table. The coal is washed across the table to a clean coal launder while the refuse passes over the end of the table to the refuse launder. Both streams then pass over sieve bends and onto a parallel bar vibrating screen for dewatering.

The plus 48 mesh cleaned coal and refuse pass onto their respective conveyors while the minus 48 mesh material, along with the process water flows to a fine coal circuit.

The first hydrocyclone is adjusted to permit only clean coal in the overflow while the underflow contains all of the refuse and some coal. The second hydrocyclone increases the accuracy of separation by discharging only refuse through the underflow while permitting only a minimal amount of refuse to be discharged with the coal in the overflow.

Overflow streams, containing clean coal from both hydrocyclones, is thickened in dewatering cyclones and proceeds to a vacuum disc filter for further water removal.

Underflow streams from the hydrocyclones are fed directly to a separate vacuum disc filter for water removal. Dewatered clean coal and refuse are delivered to the output conveyors.

All process water streams eventually flow through a mechanical clarifier where solids are removed with the aid of a flocculant. The water is then completely recycled with only enough makeup to replace the water lost with the plant product.

A heavy media cyclone circuit will be added in 1979 and will be used as an alternative to the wet concentrating table for cleaning medium size coal. The addition of the circuit will not affect other principal features of the plant, but will increase our evaluation capability.

The main plant has been used to demonstrate cleaning of large samples (1000 T) of coal from seven Iowa mines on an industrial scale and to process 40,000 tons of coal from the Iowa State University Demonstration Mine. The samples from the different mines contained from 2.5 to 8.7% total sulfur and from 11.6 to 20.0% ash. (Figure 4) As a result of processing in the plant, the total sulfur content was reduced an average of 35% with a range of 24 to 45% and the ash content was reduced an average of 45% with a range of 34 to 57% for the series of coals. Moreover the pyritic sulfur content was reduced an average of 52% with a range of 37% to 70%. The average weight yield was 75% with a range of 66 to 80% and the average calorific yield was 84% with a range of 74 to 96%. Since these results were obtained before they hydrocyclones and filters were installed, none of the -48 mesh coal was recovered and therefore the yields were lower than would be obtained with the present equipment.

IV. FROTH FLOTATION AND OIL AGGLOMERATION DEMONSTRATION UNIT

A unit for demonstrating the froth flotation and oil agglomeration methods of cleaning fine-size coal has been installed in the Ames coal preparation facility. (Figure 5 & 6) This unit includes equipment for grinding and chemically pretreating 1000 lb. batches of coal and for continuously beneficiating the pretreated coal by froth flotation or oil agglomeration at a rate of 100-200 lb/hour. The circuit also includes a means for pelletizing the beneficiated coal.

Coal fines from the Ames coal preparation plant are placed as an aqueous slurry in either of two agitated tanks which serve for both storage and chemical pretreatment. For the pretreatment step, an alkali is added to the coal slurry which is then heated to the required temperature. Air is introduced next to oxidize the surface of the pyrite particles after which the slurry is cooled to a set temperature for the subsequent separation steps. If a finer particle size is desired, the coal is ground with a ball mill before applying the chemical treatment. The ball mill circuit includes cyclones for both thickening the pulp supplied to the mill and classifying the particles according to size. Consequently, only the coarser particles enter the ball mill.

After the feed has been adequately ground and/or pretreated, it is pumped to either a bank of froth flotation cells or the first stage of the oil agglomeration system. If the feed is directed to the bank of flotation cells, a frothing agent is added and the coal is floated and removed in the froth while the refuse is removed in the underflow. The float product is either filtered to recover the coal or placed in a storage tank to await further treatment.

Either coal fines cleaned by froth flotation or coal fines which have only been chemically pretreated can be oil agglomerated. A slurry of these fines is delivered to the first stage of a two stage agglomeration system. Fuel oil is added and microagglomerates are produced by high shear mixing. The suspension of microagglomerates is conducted to a vibrating screen for dewatering and desliming. The microagglomerates are resuspended in fresh water in the second stage where less vigorous agitation promotes the coalescence and growth of large agglomerates. The suspension is then dewatered on another vibrating screen. The agglomerated coal can either be recovered at this point or conveyed to an inclined rotating disc pelletizer for further size enlargement.

Since construction of this unit was completed only recently, a program of demonstration runs is just getting underway. The results will be evaluated in terms of the recovery of combustible matter, the sulfur, ash, and moisture content of the product, and its physical properties. The effects of important parameters such as residence time, slurry concentration, reagent concentration, and temperature will be applied to several different representative coals from various regions of the country.

V. HIGH GRADIENT MAGNETIC SEPARATION

"High gradient magnetic separation" process is being investigated to determine its feasibility in cleaning high sulfur coal. In this process fine coal in a water slurry is passed through a magnetic field in which a mesh of ferromagnetic material (stainless steel wool) has been placed. The refuse, which has different magnetic properties than the coal, is attracted to the mesh thereby performing the separation. When the mesh is loaded with refuse either the magnet is turned off or the mesh is removed from the field allowing the refuse to be flushed away. This process can be enhanced by seeding the raw coal to increase the magnetic susceptibility of the refuse. This project is presently in the planning stage.

Presently, laboratory studies are underway to determine the relative merits of induction heating, microwave heating, and chemical treatment to alter magnetic properties.

VI. SLAGGING AND FOULING CHARACTERISTICS OF RAW VS CLEANED COALS

To determine the relative effect cleaning coal has on boiler operation, the ashing properties of four coals were determined before and after cleaning.

Although the number of coals was limited, the results show a significant benefit through cleaning. (Grieve, 1978)

A complete chemical analysis was performed on the ash from four coals which had widely varying sulfur content to determine the base content, acid content, base/acid ratio, silica/alumina ratio, silica value, iron value and dolomite percentage. The fouling index was computed by multiplying the base/acid ratio with the percent dry sodium and the slagging index by multiplying the base/acid ratio with the percent dry sulfur. These indexes were compared to indicate the effect cleaning coal has on boiler operation. (Attig and Dunzy 69)

Of the four coals selected, the reduction of the slagging index was least in the lowest sulfur coal and dramatically reduced in the other three. (Figure 7) A lesser reduction in the fouling index was also indicated.

The performance observed while burning these coals in the power plant correlates to the calculated values of fouling and slagging indexes.

VII. RELATED PROJECTS

Several projects are also being pursued which relate either directly or indirectly with the utilization of coal as an energy source.

An on-line nuclear sulfur and ash monitoring device is being developed to continuously measure the total ash and the total sulfur in a moving coal stream while at the same time being insensitive to the moisture level.

An on-line x-ray diffraction technique has shown that monitoring of all forms of inorganic sulfur can be continuously monitored along with other selected minerals. This device is also insensitve to moisture levels in the measured stream.

Both the nuclear and the x-ray diffraction techniques give almost instantaneous measurements (approximately 30 seconds).

A process for pelleting fine coal is being investigated with present results showing that much less pressureis required than for conventional briquetting and that higher moisture levels can be accommodated to a degree which may eliminate the customary expensive step of thermal drying.

Methods for separating fly ash into components which may be commercially utilized for the production of aluminum, iron and other metals while removing undesirable elements from the remaining rejects are being investigated.

Nuclear magnetic resonance studies of coal are being pursued to aid in characterization of the basic structure of coal.

Analysis of major, minor and trace elements in high BTU coal gas and effluents resulting from refuse derived fuels are being done using plasma fluorescence spectroscopy and other methods.

VIII. CONCLUSION

Using conventional equipment, physical coal cleaning has demonstrated the removal of 24 to 45% of the sulfur in several high sulfur coals. More intensive physical cleaning, with a smaller size consist, indicates the possibility of increasing the inorganic sulfur removal up to 88%. Research plans include beneficiation tests of various medium and high sulfur coals not previously tested with present equipment and alternate methods.

Related investigations should lead to a better understanding of the basic nature of coal, reclamation of post-combustion products, and improved analysis of process streams both in physical coal cleaning plants and in coal conversion plants.

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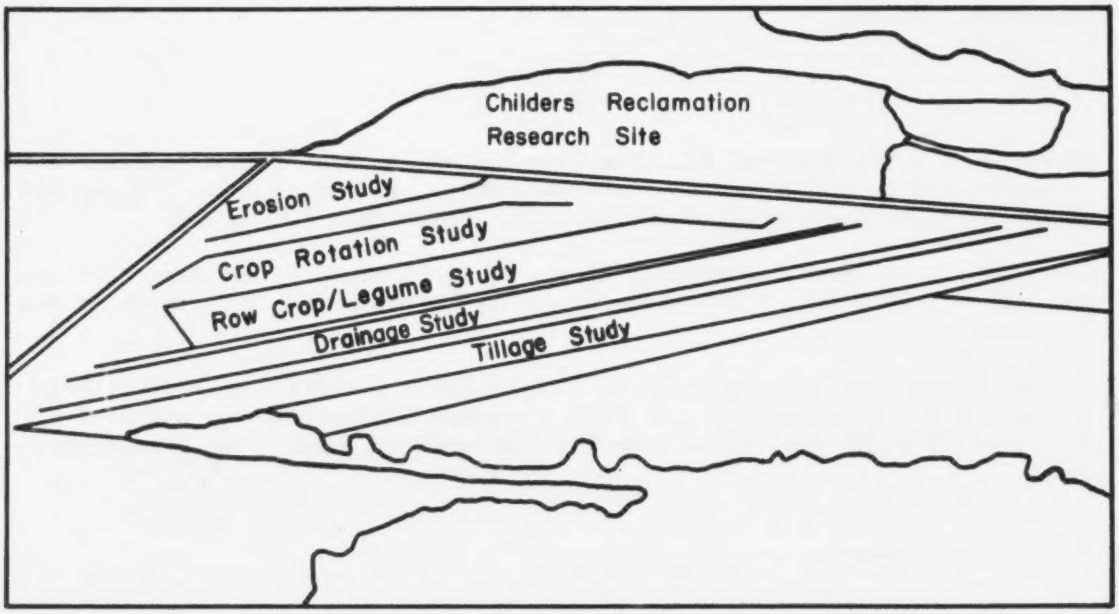
Cavallaro, R. A., and Deurbrouck, A. W., "U.S. Bureau of Mines Report of Investigations RI 8118", 1976, Pages 83 to 91, United States Department of the Interior.

Grieve, Richard A., Chu, Henry, and Fisher, Ray W., "Iowa Coal Project Preliminary Coal Beneficiation Cost Study Progress Report," Energy and Minerals Resources Research Institute, Iowa State University, Ames, Iowa (September, 1976).

Figure 1. Aerial View of Restored ICP Demonstration Mine No. 1 Site and Reclaimed Childers Research Site

Laboratory Research Areas


Childers Reclamation
Research Site
Erosion Study
Crop Rotation Study
Row Crop/Legume Study
Drainage Study
Tillage Study

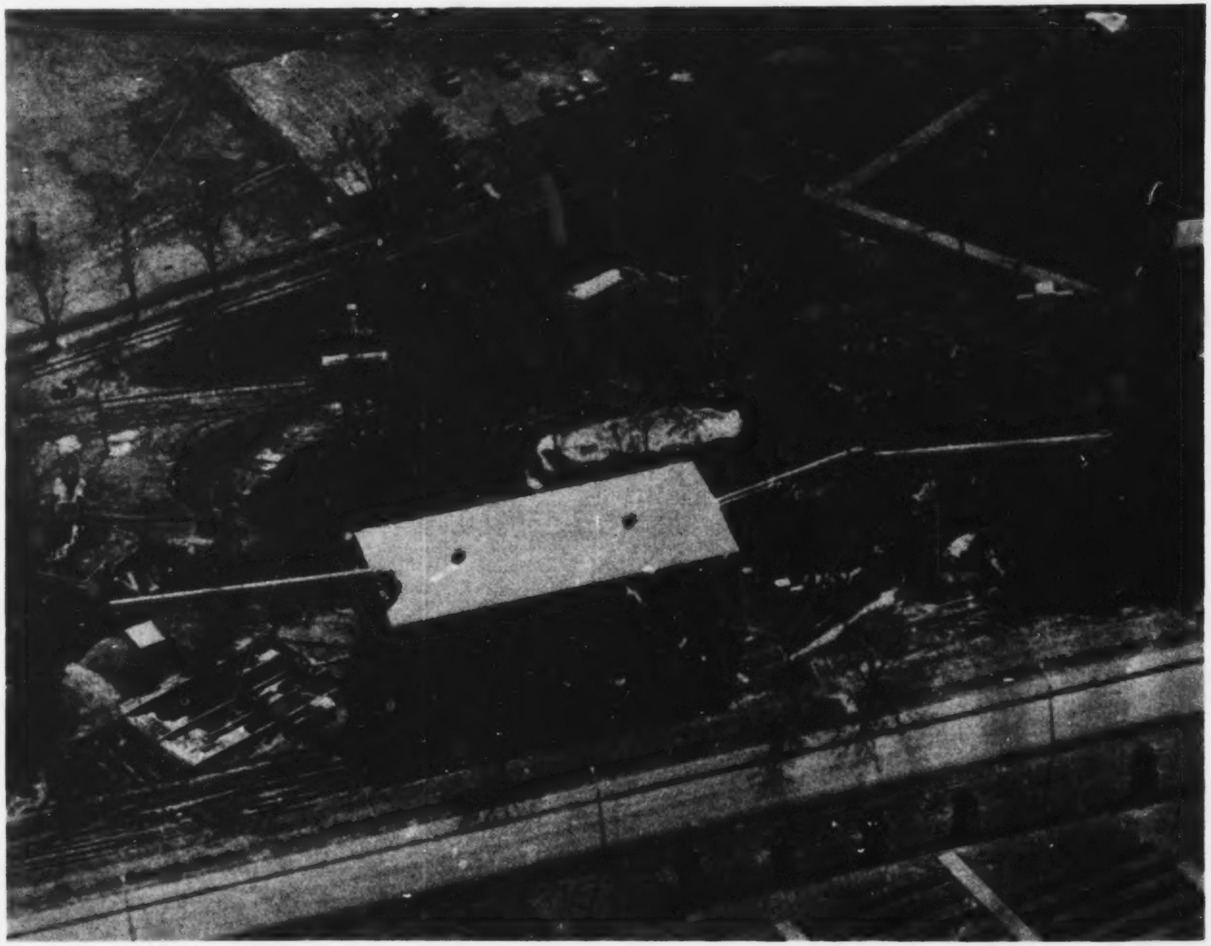


Figure 2. Aerial View of Iowa State University Coal Preparation Plant (white roof) showing close proximity to University Power Plant (Upper R.H. corner of photo)

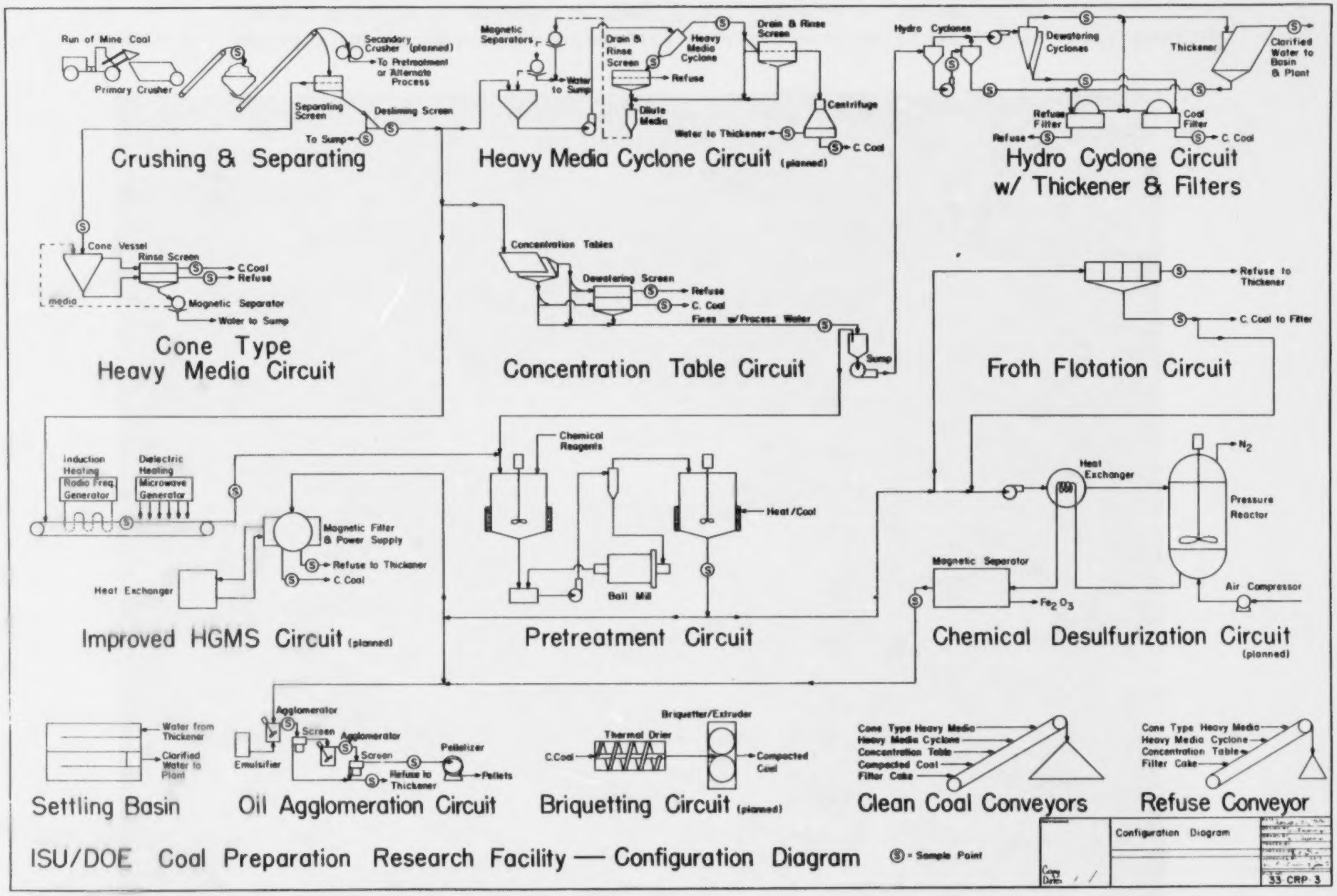

Run of Mine Coal
Primary Crusher
Secondary Crusher (planned)
To Pretreatment or Alternate Process
Separating Screen
Desliming Screen
To Sump
Crushing & Separating
Magnetic Separators
Water to Sump
Drain & Rinse Screen
Heavy Media Cyclone
Refuse
Dilute Media
Drain & Rinse Screen
Centrifuge
Water to Thickener
C Coal
Heavy Media Cyclone Circuit (planned)
Hydro Cyclones
Dewatering Cyclones
Thickener
Clarified Water to Basin & Plant
Refuse Filter
Coal Filter
Refuse
C. Coal
Hydro Cyclone Circuit w/ Thickener & Filters
Cone Vessel
Rinse Screen
C.Coal
Refuse
media
Magnetic Separator
Water to Sump
Cone Type Heavy Media Circuit
Concentration Tables
Dewatering Screen
Refuse
C. Coal
Fines w/Process Water
Sump
Concentration Table Circuit
Refuse to Thickener
C Coal to Filter
Froth Flotation Circuit
Induction Heating
Radio Freq. Generator
Dielectric Heating
Microwave Generator
Magnetic Filter & Power Supply
Refuse to Thickener
C Coal
Heat Exchanger
Improved HGMS Circuit (planned)
Chemical Reagents
Heat/Cool
Ball Mill
Pretreatment Circuit
Heat Exchanger
N_2
Pressure Reactor
Magnetic Separator
Fe_2O_3
Air Compressor
Chemical Desulfurization Circuit (planned)
Water from Thickener
Clarified Water to Plant
Settling Basin
Agglomerator
Emulsifier
Screen
Agglomerator
Screen
Pelletizer
Refuse to Thickener
Pellets
Oil Agglomeration Circuit
Briquetter/Extruder
Thermal Drier
C.Coal
Compacted Coal
Briquetting Circuit (planned)
Cone Type Heavy Media
Heavy Media Cyclone
Concentration Table
Compacted Coal
Filter Cake
Clean Coal Conveyors
Cone Type Heavy Media
Heavy Media Cyclone
Concentration Table
Filter Cake
Refuse Conveyor
ISU/DOE Coal Preparation Research Facility — Configuration Diagram
S - Sample Point
Configuration Diagram
33 CRP 3

Figure 3. Configuration Diagram

Coal Processed	Specific Gravity	Size		BTU/lb	Total Sulfur (%)	Pyritic Sulfur (%)	Ash (%)	Moisture (%)	Lbs SO_2/MMBTU	Tonnage Yield (%)	BTU Yield (%)	Ash Reduction (%)	Pyritic Sulfur Reduction (%)	Total Sulfur Reduction (%)	SO_2 Reduction (%)
ISU #1	1.5	1½"X 48M	Raw	10,572	6.95	----	16.21	9.24	13.15	80.0	85.7	33.7	----	29.2	34.0
			Clean	11,312	4.91	----	10.73	9.39	8.68						
ICO	1.35	1" X 48M	Raw	10,690	5.48	----	11.55	12.9	10.25	73.6	78.3	39.4	----	40.4	43.9
			Clean	11,724	3.37	----	7.22	10.2	5.75						
Lovilia[1]	1.50	1½"X 48M	Raw	9,839	2.51	1.77	17.16	11.74	5.10	74.9	86.7	46.5	37.0	23.6	33.9
			Clean	11,868	2.0	1.16	9.57	8.0	3.37						
Mich	1.40	1½"X 48M	Raw	10,222	8.74	6.66	24.51	3.26	17.10	72.7	82.9	40.8	55.7	36.3	44.2
			Clean	11,434	5.46	2.89	14.22	5.12	9.55						
Shinn	1.35	1½"X 48M	Raw	10,558	4.56	3.25	15.99	8.65	8.64	66.3	74.0	46.4	44.1	27.0	34.8
			Clean	12,058	3.40	1.86	8.77	6.49	5.63						
Big[1] Ben	1.60	1½"X 48M	Raw	9,368	4.76	3.90	21.34	18.32	10.16	78.5	86.9	48.8	51.3	42.6	48.2
			Clean	10,511	2.50	1.58	9.84	15.57	4.76						
Jude	1.45	1½"X 48M	Raw	8,070	7.84	6.11	29.96	9.04	19.43	70.8	96.4	56.9	70.2	44.8	59.4
			Clean	10,709	4.22	1.77	12.58	11.39	7.88						
Average of all Coals Tested	1.40	1½"X 48M	Raw	9,903	5.83	4.34	19.53	10.45	11.98	73.8	84.4	44.6	51.7	34.8	42.6
			Clean	11,374	3.69	1.85	10.42	9.45	6.52						
						B.O.M. Comparative Data (1) 1½" X 100M @ 1.40 S.G.				72.3	78.8	46.5	59.5	38.0	43.3

[1] Deep Mine. All others surface mines.
[2] Losses in yield computations include fines (-48M) losses.

All proximate analysis - Air dried basis.
All reduction factors - Moisture free basis.

Figure 4. Iowa Coals Processed at Iowa Coal Project Preparation Plant
Data Represents Best Run Made on Each Coal

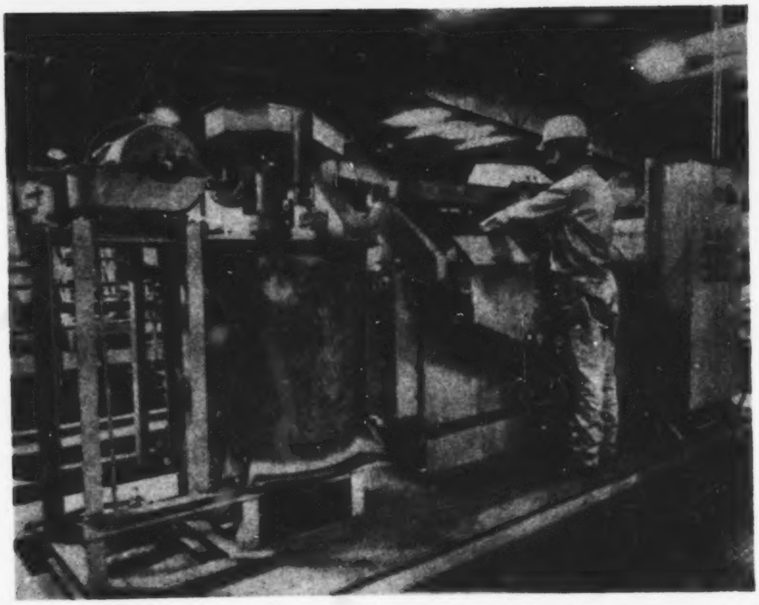


Figure 5. The recovery of fine coal will be demonstrated by this unit consisting of reagent feeder, conditioning tank, and bank of four froth flotation cells.

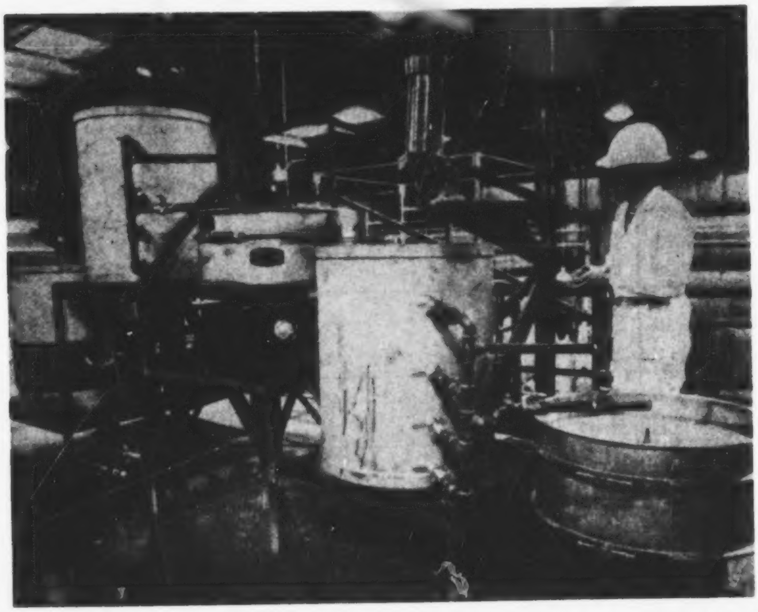


Figure 6. The oil agglomeration and recovery of fine coal will be demonstrated by this system of agitated tanks and dewatering screens.

	ISU (strip mined)		Lovilia (deep mined)		MICH (strip mined)		ICO (strip mined)	
[1]Coal Proximate Analysis	RAW	CLEANED	RAW	CLEANED	RAW	CLEANED	RAW	CLEANED
% Sulfur	11.52	5.42	2.23	2.17	8.74	5.46	7.10	4.94
% Ash	17.86	11.84	12.06	10.40	24.51	14.22	18.28	8.94
BTU	11,384	12,484	12,534	12,901	10,222	11,434	10,896	11,794
Specific Gravity								
Ash Analysis								
[2]Ash Fusion Temp (F°)	2,087	2,110	2,107	2,150	2,037	2,073	2,147	2,153
Base Content	52.63	35.01	40.39	39.35	53.99	46.78	76.10	65.01
Acid Content	34.41	60.61	50.24	49.74	33.17	36.98	14.82	31.16
Base/Acid Ratio	1.53	.58(62%)[3]	.80	.79(1%)[3]	1.63	1.27(22%)[3]	5.13	2.09(59%)[3]
Silica/Alumina Ratio	1.83	1.67	2.03	2.34	2.09	1.95	1.35	2.31
Silica Value	30.39	50.78	47.20	48.66	29.59	35.14	10.11	24.69
Iron Ratio	2.49	4.51	1.48	1.12	3.07	1.51	4.90	8.95
Dolomite Percentage	27.61	17.15	37.39	43.76	24.15	38.26	16.77	9.77
[4]Fouling Index	.20	.09	.29	.33	.09	.02	.13	.03
[5]Slagging Index	17.63	3.14	1.78	1.71	14.72	7.32	38.17	11.24

Fouling Type		Slagging Type	
Low	Less than 0.2	Low	Less than 0.6
Medium	0.2 - 0.5	Medium	0.6 - 2.0
High	0.5 - 1.0	High	2.0 - 2.6
Severe	Greater than 1.0	Severe	Greater than 2.6

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1. Air dried basis
2. Average of Initial Deformation, Fusing, and Fluid Temperature under reducing atmosphere conditions
3. Percent reduction from raw coal.
4. (Base/acid ratio) X (%Na)
5. (Base/acid ratio) X (Dry %s)

Figure 7. Comparison of Ashing Properties of Raw vs Beneficiated Coals

CLEANING OF EASTERN BITUMINOUS COALS BY FINE GRINDING, FROTH FLOTATION AND HIGH-GRADIENT MAGNETIC SEPARATION

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ABSTRACT

Mineralogical and bench-scale beneficiation studies were conducted with five Eastern bituminous coals to develop processes so as to recover 85 percent of the Btu value of the coal while rejecting 85 percent of the pyritic sulfur and the ash. The coals studied were from the Illinois, Pittsburgh, Middle Kittaning, Hartshorne and No. 12 Coal Bed seams. The desired results were obtained reasonably well by fine grinding of the raw coal, followed by froth flotation and treatment of flotation concentrates or middlings by high gradient magnetic separation. Alternative flowsheets involving froth flotation alone or regrinding and retreatment of middlings fractions also gave reasonably good results.

Several different treatment processes have been demonstrated in a pilot plant treating 400 pounds of raw coal per hour, using either Illinois or Pittsburgh seam coal as feed.

The processes described have not been optimized and a number of potentially useful variations suggest themselves. Preliminary economic analyses have been made with the available results. The overall program has demonstrated that raw coal can be cleaned by employing the general approach commonly employed in treatment of metallic ores.

INTRODUCTION

Coal cleaning by physical means is presently receiving much attention as a means of reducing environmental problems associated with coal combustion. These problems arise from the ash and sulfur contents of the coal and from the presence of trace amounts of hazardous elements such as heavy metals, beryllium, selenium and arsenic. Cleaning by physical means can reduce the ash and pyritic sulfur contents of the coal. Hazardous trace elements will be removed to the extent that these materials follow the waste rather than the coal.

Coal cleaning as presently practiced in the U.S. generally employs gravity concentration of coarsely crushed coal and treatment of the fines produced during crushing by froth flotation, cycloning or screening. For many eastern bituminous coals, liberation of pyrite and ash from the coal is largely incomplete at the sizes employed in the washing operations (Cavallaro, 1976). No coal cleaning plants deliberately grind coal to a very fine size to achieve substantial liberation of ash and pyrite.

On the basis of these considerations a research contract was awarded to Michigan Technological University by the U.S. Bureau of Mines (subsequently being transferred to the U.S. Department of Energy) to investigate coal cleaning by means of mineral processing techniques commonly employed for treatment of base metal sulfide ores. Processes of particular interest included fine grinding, regrinding of middling products and application of separation processes such as froth flotation and high gradient magnetic separation. Targets set forth in the contract were to recover 85% of the BTU value of the raw coal while recovering 15% or less of the ash and of the pyritic sulfur.

Project Scope - Coal Samples

The contract called for laboratory investigation of several coals to be selected by DOE. Samples of five eastern bituminous coals were obtained, as listed in Table 1.

Laboratory studies were conducted with the five coals to develop processes capable of achieving the desired targets. The resulting processes were then tested further in pilot plant campaigns with the Illinois No. 6 Seam and Pittsburgh No. 8 Seam coals. These campaigns totalled 15 days of three-shift operation and 10 days of single shift operation.

This paper will be concerned primarily with the laboratory development of the treatment processes and subsequent demonstration of these processes in the pilot plant. It should be emphasized that the processes as described and the results obtained are not necessarily optimum. The scope of the project did not allow for such detailed investigation.

The paper will concentrate on the work done with the Illinois and Pittsburgh Seam coals. Results obtained with the other three coals were generally similar.

Chemical Analyses

ASTM analytical procedures were used for determining ash, sulfur in all forms, moisture and calorific value. To minimize the need for calorimetric analyses on a large number of test products, an equation for calculating the coal analysis of a test product was developed as follows:

$$\%(\text{Coal}) = 100 - \%(\text{Ash}) - 1.6(\%\text{PyS}).$$

Estimated coal analyses obtained by this relation were then used to determine the coal recovery in a given laboratory or pilot plant test. These recoveries were compared with BTU recovery values determined from calorimetric measurements for a number of tests as listed in Table 2. In general the comparisons were reasonable and the estimated coal recoveries tended to be a little low, thus making analysis of the test results conservative. The results described in this paper are in terms of coal recoveries.

FLOWSHEET DEVELOPMENT

Size of Grind

All of the coal samples contained pyrite and ash grains from several hundred microns in diameter down to only a few microns. Examples of very fine pyrite and ash are shown in Figures 1 and 2.

These observations clearly demonstrated the impracticality of grinding coal to such a size that the pyrite and ash would be completely liberated. Instead, the coal would have to be processed at some size where a part of the ash and pyrite remained locked with coal in middling grains. The desired size of grinding for each coal was established on the basis of meeting the desired processing targets and ranged from -150 mesh to -325 mesh.

Application of Individual Treatment Processes

Three separation processes were studied individually in the laboratory--froth flotation, high gradient magnetic separation and selective agglomeration (or bulk oil separation). Samples of raw coal were stage crushed through 10-mesh and stored in tightly closed containers to provide feed material for laboratory tests.

Froth flotation. Laboratory flotation tests were made with 300g charges of -10 mesh raw coal. The coal was ground wet at 50% solids in a laboratory rod mill. Flotation was done in a laboratory Fagergren machine. Distilled water was used throughout.

Two stages of flotation were employed--a rougher stage, at about 12% solids, followed by refloating the rougher froth in a cleaner stage at about 9% solids. Coal was floated with MIBC (methyl isobutyl carbinol) alone or with No. 1 fuel oil. The flotation pH was adjusted to 8.5 with sodium hydroxide.

Variations in coal, ash and pyrite recoveries were controlled primarily by varying the size of grind and the collector additions. The coarser the coal, the more collector was required to float it.

Figures 3 and 4 summarize flotation results obtained in the laboratory with the Illinois Seam coal. Two sizes of grind were studied, -150 mesh and -325 mesh. (As used in this paper, the term "-150 mesh grind", for example, means the ground coal was 90% to 95% -150 mesh in size.) The flotation collector used was a mixture of MIBC and No. 1 fuel oil.

The curves in Figure 3 demonstrate that pyrite rejection at a given coal recovery improved substantially as the coal was ground finer. Grinds finer than about 90% -325 mesh were not tested because it was felt that such fine grinding would prove impractical. No significant improvement in ash rejection resulted from grinding finer than about 90% -150 mesh with the Illinois coal.

With a -325 mesh grind for Illinois Seam coal, the pyrite recovery was about 30% and the ash recovery about 17% at 85% coal recovery. Reagent additions were 1.2 lb of NaOH, 1.05 lb of MIBC and 1.55 lb of fuel oil per ton of raw coal processed.

Somewhat better results were obtained with the Pittsburgh No. 8 Seam coal with -325 mesh flotation feed. At 85% coal recovery, pyrite and ash recoveries were 24% and 11% respectively. Reagent additions were 0.20 lb of NaOH, and .50 lb of MIBC per ton of coal.

High gradient magnetic separation (HGMS). Laboratory HGMS tests were conducted with a mobile unit leased from Aquafine Corporation. This machine is a cyclic separator using a cylindrical canister filled with magnetic matrix as the separating chamber. Tests were made with a canister 1" diameter by 20" long, packed with pads of magnetic stainless steel wool. The canister was placed in a magnetic field of 20 kilogauss (as measured in open space).

The magnet operating cycle consisted of pumping feed slurry upward through the canister with the magnet on. Then, with the magnet still on, the feed slurry was replaced with a flow of fresh water to purge non-magnetics entrained in the steel wool matrix. Finally, with the magnet off, magnetic material was flushed from the canister with a down flow of high velocity water.

Variables of the magnet operation included the feed rate of coal slurry and purge water (expressed in terms of the equivalent retention time of slurry in the canister), the duration of each of the three parts of the total cycle and the solids content of the feed slurry. Many sets of conditions were tested. Those ultimately considered best were a feed of 15% solids at a retention time of 0.75 minutes and a cycle program of 3 minutes of feed on, 1.5 minutes of purge and 1 minute of flushing. These conditions were maintained throughout the pilot plants runs. Longer retention time improved pyrite removal, but coal losses in the magnetic product also increased and the capacity of the machine decreased. Matrix packing was 6% by volume in the canister.

The results obtained with HGMS from Illinois No. 6 Seam coal are shown in Figure 5. In these tests charges of -10 mesh coal were slurried with water and deslimed prior to grinding to 90% -325 mesh. This initial desliming removed over half of the ash. Such treatment was found essential to obtaining reasonable results by HGMS. If raw coal was used as the magnet feed, ash material was removed in preference to pyrite. As there is considerably more ash than pyrite in raw coal, pyrite removal from raw coal was generally poor.

The results presented in Figure 5 are about the same as those obtained by flotation. For a coal recovery of 85%, the ash and pyrite recoveries were 25-30%. Furthermore, the curves are very steep in this region of coal recovery. Control of plant operations would be difficult to maintain under these conditions.

Selective agglomeration. A limited study was made of the application of selective agglomeration by treatment with bulk oil to the cleaning of raw coal. In these tests dilute slurries of coal in water were mixed with varying amounts of No. 2 fuel oil. Mixing was done at high shear in a blender. The coal particles combined with the oil to form agglomerates. These were screened away from the water phase which contained the unagglomerated ash and pyrite fines.

Results obtained with Hartshorne Seam coal are shown in Figure 6. At 85% coal recovery, pyrite recovery was about 35% and ash rejection about 28%. These separations were not efficient and did not appear to be better than could be obtained more conveniently by froth flotation. Therefore, the use of selective agglomeration as a primary separation process was abandoned early in the project and emphasis was placed on froth flotation and HGMS.

Processing by Froth Flotation and HGMS

None of the three separation processes studied was successful by itself in obtaining the desired results on treating raw coal. However, the results suggested that treatment by both froth flotation and HGMS would be effective. Flotation was effective in removing ash and a substantial part of the pyrite. The flotation concentrate would then be a desirable feed to HGMS to reduce the pyrite and ash contents to the target levels.

On this basis laboratory tests were run according to the flowsheet shown schematically in Figure 7. The coal was ground to about 90% -325 mesh and treated by two stages of flotation as before. The flotation concentrate was then treated by HGMS and the non-magnetic product was the finished clean coal.

Typical results as obtained with the Illinois No. 6 Seam coal are presented in Figure 8. For an overall coal recovery of 84%, the pyrite recovery was 15% and the ash recovery was 9%. The clean coal analysis was 5.8% ash and 0.36% pyritic sulfur. Corresponding results obtained with Pittsburgh Seam coal were 16% pyrite recovery and 11% ash recovery for 85% coal recovery.

A key to the success of this process was to recover 92% to 95% of the coal in the flotation circuit to insure an overall coal recovery of 85%. Coal lost in the flotation tailings was irretrievable in the process sequence employed. Flotation reagent consumptions were about 1.05 lb of MIBC and 1.50 lb of fuel oil per ton for the Illinois Seam coal and 0.51 lb of MIBC per ton for the Pittsburgh coal. HGMS operation was the same as already described.

PILOT PLANT OPERATION

Flowsheet A - Illinois Seam Coal

After study in the laboratory the combined flotation-HGMS process was tested in a continuous pilot plant operation treating 400 lb of raw coal per hour. The first flowsheet employed, termed Flowsheet A, is shown in Figure 9. The first pilot plant operation was with Illinois No. 6 Seam coal.

There were two principal differences between this flowsheet and that followed in the laboratory. First the pilot plant grinding circuit employed two stages of grinding--an open circuit rod mill followed by a ball mill operating in closed circuit with a cyclone. The cyclone overflow was the flotation feed. The second difference was the incorporation of a 200-mesh square mesh screen to screen the

the flotation concentrate prior to treatment with HGMS. The screen was introduced initially to protect the magnet from any +200 mesh material in the flotation concentrate, which would tend to clog the steel wool magnet matrix. Both of these flowsheet differences proved important in the pilot plant operation.

A 5-inch diameter canister was used in the HGMS during pilot plant operations. Slurry and purge water feed rates were scaled up from laboratory conditions according to the ratios of cross-sectional areas of the pilot plant and laboratory canisters.

Grinding. The cyclone overflow obtained at the start of the pilot plant contained about 27% +325 mesh material, compared with a desired value of 10%. Furthermore, the size distribution of the cyclone overflow was substantially different from that obtained in a laboratory grind, as seen in Figure 10. The coal ground in the pilot plant was deficient in material between 15 to 40 microns, but contained an excessive amount of material coarser than 50 microns (or say 270 mesh). A number of changes were made in the grinding circuit to grind this coarse fraction further. The best that could be done without reducing the feed rate was to produce a cyclone overflow containing 19% +325 mesh material.

Screening. Samples of the +270 mesh fraction of the cyclone overflow obtained with the Illinois Seam coal assayed about 0.5% pyritic sulfur and about 5.5% ash. These analyses were as good or better than could be obtained in the non-magnetic product from HGMS in the pilot plant with this coal. Therefore, it was decided to remove this coarse material as finished coal by screening. This was accomplished with the 200-mesh screen treating the flotation concentrate ahead of magnetic separation. The screen oversize was combined with the non-magnetics from HGMS as the final concentrate.

Results. The pilot plant was operated with Flowsheet A for 15 consecutive 8-hour shifts with Illinois No. 6 Seam coal as feed. Samples were collected during each shift.

Several changes in operation were made during this period. These included varying the grind between 19% and 27% +325 mesh and varying the additions of flotation reagents. The overall results from all of these shifts are summarized in Figure 11 in terms of the recoveries of coal, pyrite and ash in the finished cleaned coal. The figure also includes two points representing typical pyrite and ash recoveries from a laboratory test.

The data in Figure 11 cluster about two curves, one for pyrite recovery and the other for ash, over a wide range of coal recovery. Results reasonably close to the desired targets were obtained. In the pilot plant, at 85% coal recovery, the pyrite recovery was about 24% and ash recovery about 16%. Pyritic sulfur and ash analyses were 0.40% and 8.3% respectively.

However, the selectivity of separation was not as good in the pilot plant as in the laboratory. The principal difference was in the flotation circuit. Pyrite and ash recoveries were 5% or more higher for a given coal recovery in the pilot plant flotation circuit with the Illinois No. 6 coal.

Flowsheet A - Pittsburgh No. 8 Seam Coal

The second pilot plant campaign was conducted with Pittsburgh No. 8 Seam coal, again with Flowsheet A. Again the cyclone overflow contained about 27% +325 material as compared with 10% in the laboratory grind. The pilot plant was operated for 15 shifts.

Several changes were made in an effort to improve the flotation results. The solids content of the flotation pulps in the rougher and cleaner stages were varied between 10% and 15% and the flotation times in the rougher and cleaner stages were varied.

The results obtained during this operation are presented in Figure 12. Again the results cluster about two lines and again, while results reasonably close to the target values were obtained, the performance was not as good as had been obtained in the laboratory. Failure to obtain proper selectivity in the pilot plant flotation still remained the problem.

For a total coal recovery of about 85%, the pyritic sulfur and ash analyses of the cleaned coal were typically 0.63% and 5.8% respectively. The corresponding pyritic sulfur and ash recoveries were 22% and 17%.

Flowsheets B and C - Pittsburgh No. 8 Seam Coal

In the third and last week of pilot plant operation, run with Pittsburgh No. 8 Seam coal, two major changes were made consecutively in an effort to improve flotation and thereby improve the overall results. The total run was for 15 shifts.

Flowsheet B. The first change, called Flowsheet B, is shown in Figure 13 by the solid lines. The cyclone overflow was screened on a DSM screen and the oversize and undersize fractions were floated separately. The two flotation concentrates were then combined and treated as in Flowsheet A. (In Figure 13 the primary rod mill-ball mill-cyclone circuit has been omitted for simplicity.)

This change was made because there was reason to believe that the presence of coarse coal along with fine coal in the flotation circuit was the cause of the decrease in flotation selectivity. Laboratory results had established that more flotation collector was required, the coarser the coal being floated. In the first two pilot plant runs, required collector additions had tended to be higher than in the laboratory to attain desired coal recovery values. With insufficient collector additions in the pilot plant, coarse coal was readily observed in the flotation tailings.

These factors raised the possibility that excessive collector was being required in the pilot plant to float the large amount of +325 mesh coal. This could lead to decreased flotation selectivity, particularly for the fine sizes.

Flowsheet C. The second change, made during the last five shifts of the

15 shift run, was to regrind the DSM oversize material before flotation. This flowsheet is shown by the dotted lines in Figure 13. The DSM oversize was passed through a ball mill-cyclone closed circuit and was ground to about 13% +325 mesh, the same size as the DSM undersize product. During this period of operation, then, the size distribution of the flotation feed was close to that used in the laboratory tests which was about 10% +325 mesh.

The reground DSM oversize and the DSM undersize were floated in separate circuits as in Flowsheet B. The rest of the circuit was also the same as for Flowsheet B.

Results. The results obtained with Flowsheets B and C are presented in Figure 14. Two lines are presented for pyrite recovery versus coal recovery, one for Flowsheet B and one for Flowsheet C. However, the difference between these lines is small and may not even be real. There was no difference in the ash recovery obtained with the two circuits.

Comparison of the results in Figures 12 and 14 demonstrates that a small reduction in pyrite recovery was obtained in going from Flowsheet A to Flowsheets B and C. Ash recovery appeared to be unaffected. At 85% coal recovery, pyrite recovery was 20-21% and ash recovery was 17%.

Thickening and Filtration

Some of the pilot plant concentrates were thickened and filtered to gain some information about these problems. The coal was flocculated with Superfloc 127 prior to thickening. Thickener feed contained about 10% solids and the underflow about 35% solids.

Filtration was done on a vacuum drum filter. The coal readily formed a cake about 0.75 inches thick which discharged easily. Filter cake moisture was about 35%.

DISCUSSION

Pilot Plant Operation

Mechanically, the pilot plant operations went very smoothly. The only difficulty encountered in handling the coal was that the Pittsburgh Seam coal tended to be sticky and hung in the feed bin. The flotation machines were easy to control and the froth was handled readily.

HGMS operation was completely automated. Except for periodic recording of operating conditions, the machine was left unattended. Constant flow rates of feed coal slurry and purge water were maintained with a Moyno pump. Flush water was fed directly from the pilot plant main. Pulsing of this flow by a fast-acting solenoid valve provided better removal of magnetics than did a continuous flow. The magnet feed slurry had to be free of +200 mesh material to prevent plugging of the steel wool matrix. The 5-inch canister processed 80-90 lb of solids per hour.

Efficiency of Separation Processes

The laboratory and pilot plant results clearly demonstrated that ash and pyrite can be effectively removed from bituminous coal, while maintaining high coal recovery, in a circuit employing fine grinding, froth flotation and high gradient magnetic separation of the flotation concentrate. Fine screening of the cyclone overflow or flotation concentrate may be useful if the coarse fraction is clean coal.

Typical laboratory and pilot plant results obtained with Illinois No. 6 Seam and Pittsburgh No. 8 Seam coals are summarized in Table 3. Figure 15 presents a complete materials balance for one shift of pilot plant operation with Illinois Seam coal.

The initial targets of 85% coal recovery and 15% recovery for ash and for pyrite were closely attained in the pilot plant and often exceeded in the laboratory. There remains an unexplained difference in the flotation results obtained in pilot plant as compared with laboratory. Recent data suggest that the problem was in the pilot plant flotation circuit itself, rather than due the manner of preparing flotation feed. However, the source of the problem remains unidentified.

Cost Analysis

A detailed cost analysis of the overall process as illustrated in Figure 9, Flowsheet A, has not yet been made. However, the two principal cost centers will undoubtedly be grinding and HGMS. The energy required for grinding in the pilot plant totalled 39 KWH/ton of raw coal.

Capital and power costs for these operations have been estimated for a plant treating two million tons per year of raw coal. These estimates are presented in Table 4. Operating time for the plant was assumed to be 90% of 365 days per year. Also, plant results were assumed to be about 85% coal recovery and 15-20% recovery of each of the ash and pyrite. If more pyrite and ash can be tolerated in the clean coal, coal recovery would be higher and capital and operating costs might be lower (due to decreased costs for either or both of grinding and HGMS).

The costs presented in Table 4 represent only a part of the total costs required for the coal cleaning operation. However, they may be compared with present coal preparation costs. A recent analysis of operating jig and heavy media plants showed total costs in the range of $2.00 to $3.50 per ton of raw coal processed (Hoffman-Munter Corp., 1978).

Further Work

There are at least three major areas of study which will be required before treatment of coal by processes like those described can be applied commercially. The first is to optimize the process for a given coal to reduce costs. Undoubtedly, the overall efficiency can be improved over the results described in this paper. In particular, improvement in the flotation efficiency should be possible. Also, any increase in coal recovery, as by retreatment of middlings, will be very important. Finally, the trade-off between cost on the one hand and separation efficiency on the other must be studied.

A second problem will be to transform the fine coal concentrate to a form suitable for handling, transportation and use by the consumer. This most likely will mean dewatering to an acceptable level and production of agglomerates such as briquettes or pellets.

Finally, acceptable methods of disposal must be developed for the fine tailings.

Acknowledgements

The authors wish to express their appreciation to the U.S. Department of Energy and the U.S. Bureau of Mines for their support of this study. We also wish to express our appreciation to Mr. Donald H. Rose and the other members of the analytical chemistry laboratory at Michigan Technological University for performing the necessary chemical analyses.

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Cavallaro, J.A., M. T. Johnson and A.W. Deurbrouck. 1976. Sulfur reduction potential of the coals in the United States. U.S. Bureau of Mines Report of Investigation No. 8118.

Hoffman-Munter Corporation. 1978. An engineering/economic analysis of coal preparation plant operation and cost. Report to U.S. Department of Energy. Contract No. ET-75-C-01-9025.

TABLE 1

SELECTED COALS

	COAL SEAM	% SULFUR			% ASH
		TOT.	PY.	OX.	
1.	ILLINOIS NO. 6	2.02	1.39	0.06	26.0
2.	COAL BED NO. 12	2.80	2.14	0.04	31.0
3.	HARTSHORNE	1.05	0.51	0.004	16.3
4.	MIDDLE KITTANING	1.22	0.69	0.07	27.1
5.	PITTSBURGH NO. 8	3.25	2.29	--	33.3

TABLE 2

CALCULATION FOR ESTIMATING COAL ANALYSIS OF TEST PRODUCTS

$$\%(\mathrm{COAL}) = 100 - \%(\mathrm{ASH}) - 1.6\%(\mathrm{PyS})$$

* * * * * * * * * * * * * * *

% COAL RECOVERY AS CALCULATED FROM	
EST. COAL ANALYSES	CALORIMETRIC BTU DET'NS.
62.0	63.0
76.4	80.3
77.2	79.2
80.4	82.6
81.5	80.9
85.7	89.3
87.3	90.7

TABLE 3. COMPARISON OF LABORATORY AND PILOT PLANT RESULTS

A. ILLINOIS NO. 6 SEAM COAL

CLEANED COAL FROM	WT. %	ASSAY %				DIST. %			
		TOT.S	PyS	ASH	BTU/LB	COAL	TOT.S	PyS	ASH
LABORATORY	55.6	1.32	0.365	5.78	13,300	83.5	36.3	14.6	9.1
PILOT PLANT	64.1	1.36	0.420	7.73	13,200	85.0	43.2	25.8	16.9

	LB SO_2/MM BTU (APPROX.)
RAW COAL	4
CLEANED COAL	2

B. PITTSBURGH NO. 8 SEAM COAL

CLEANED COAL FROM	WT. %	ASSAY %				DIST. %			
		TOT.S	PyS	ASH	BTU/LB	COAL	TOT.S	PyS	ASH
LABORATORY	64.0	2.00	0.544	4.96	14,300	83.1	37.1	14.4	13.4
PILOT PLANT	65.7	2.00	0.665	5.66	13,900	83.1	38.1	20.9	16.2

	LB SO_2/MM BTU (APPROX.)
RAW COAL	6
CLEANED COAL	3

TABLE 4

ESTIMATED CAPITAL AND POWER COSTS FOR GRINDING AND HGMS

BASIS: 2 MILLION TONS RAW COAL PER YEAR
250 TONS PER HOUR
POWER AT 2.5¢/KWH

	CAPITAL COST		POWER COST	TOTAL
	TOTAL	$/TON	$/TON	$/TON
GRINDING	$3.3MM	0.25	0.95	1.20
HGMS	$24 MM	1.90	0.50	2.40

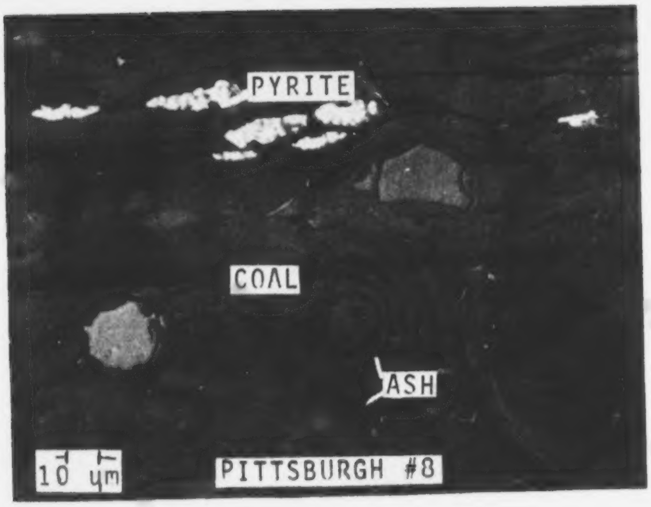

PYRITE
COAL
ASH
10 μm
PITTSBURGH #8

FIGURE 1. PHOTOMICROGRAPH OF PITTSBURGH NO. 8 SEAM COAL.

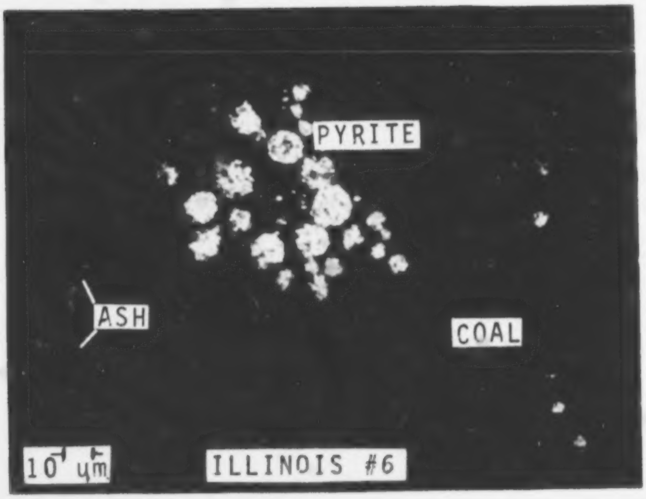

PYRITE
ASH
COAL
10 μm
ILLINOIS #6

FIGURE 2. PHOTOMICROGRAPH OF ILLINOIS NO. 6 SEAM COAL.

FIGURE 3

LABORATORY FLOTATION RESULTS - ILLINOIS NO. 6 COAL

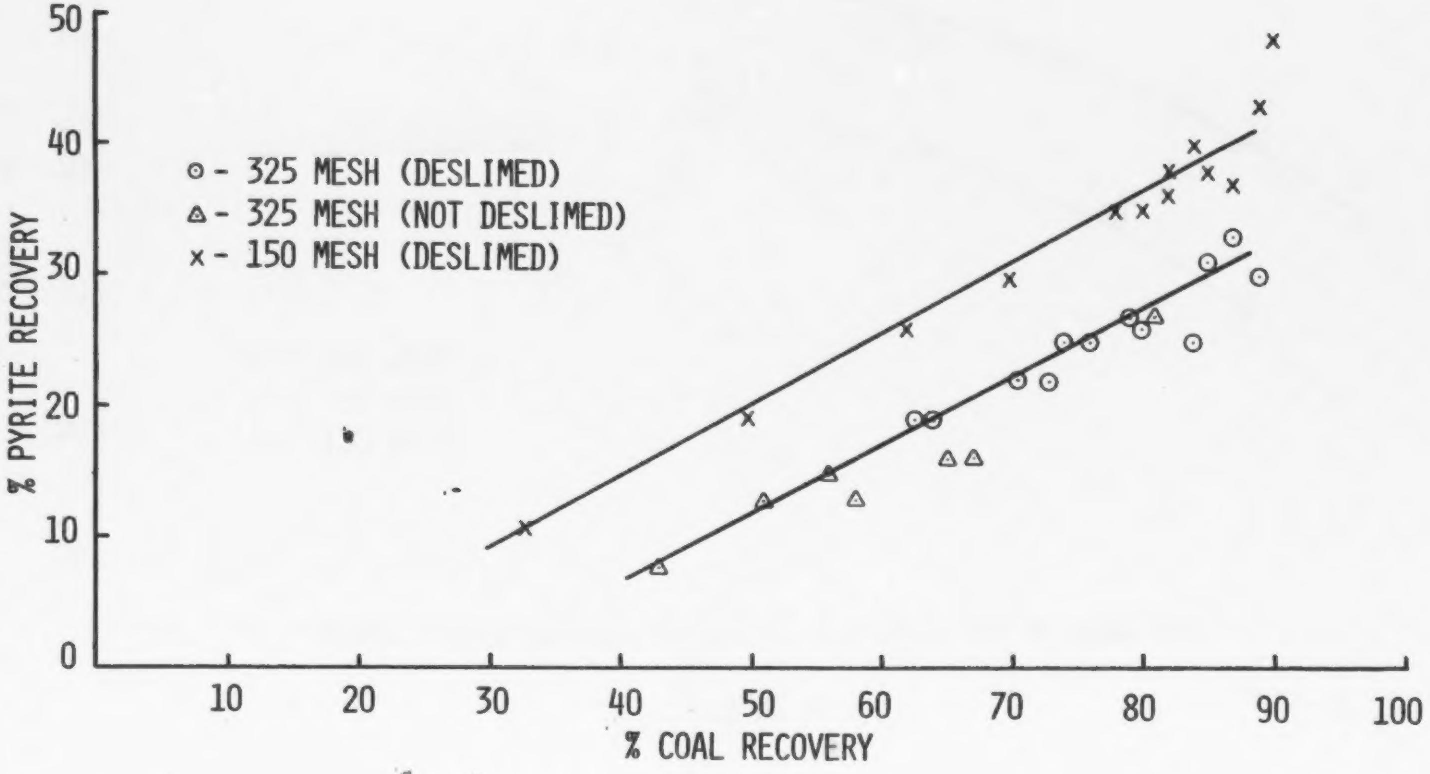
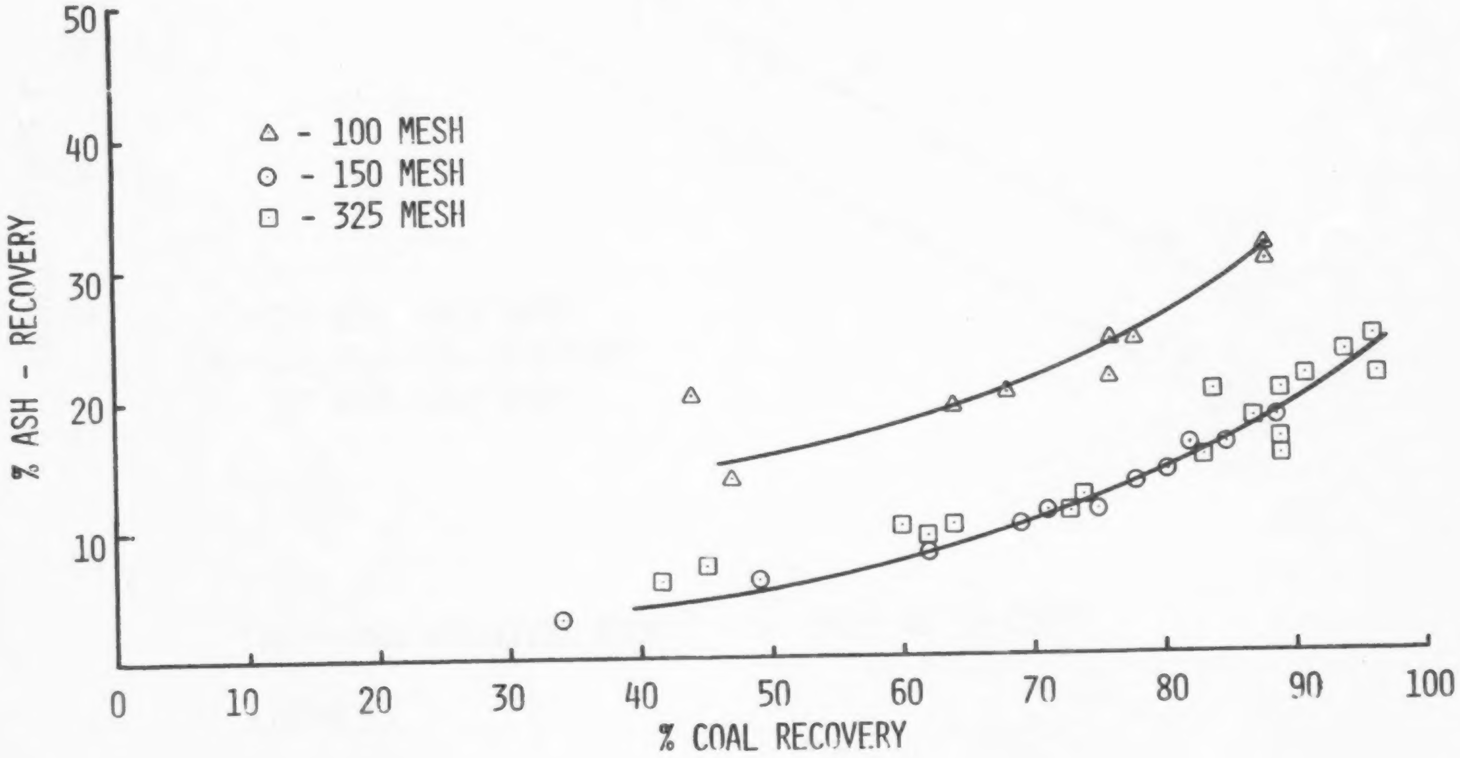


FIGURE 4

LABORATORY FLOTATION RESULTS - ILLINOIS NO. 6 SEAM COAL



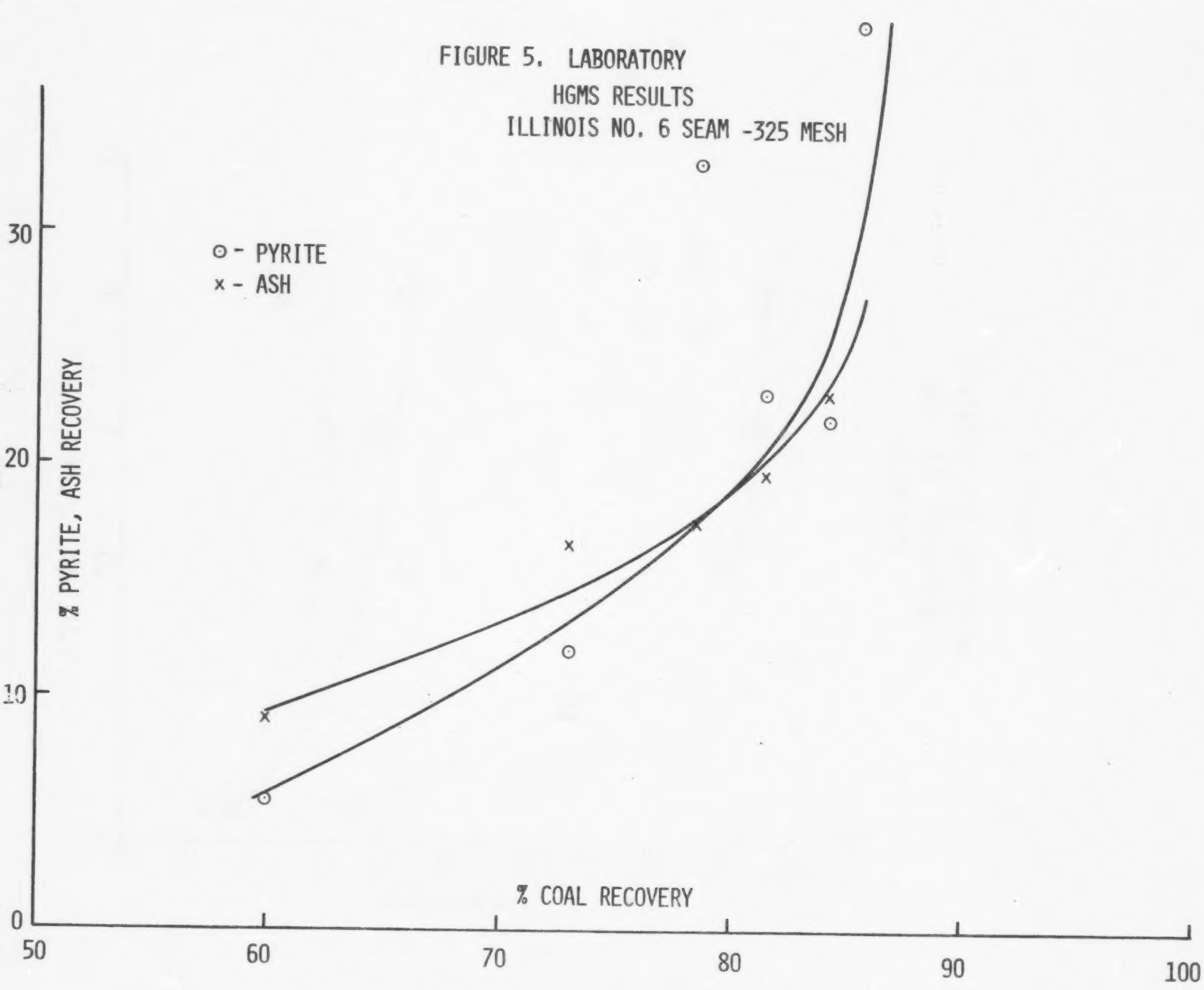


FIGURE 5. LABORATORY
HGMS RESULTS
ILLINOIS NO. 6 SEAM -325 MESH

FIGURE 6

SELECTIVE AGGLOMERATION
HARTSHORNE SEAM COAL
-200 MESH

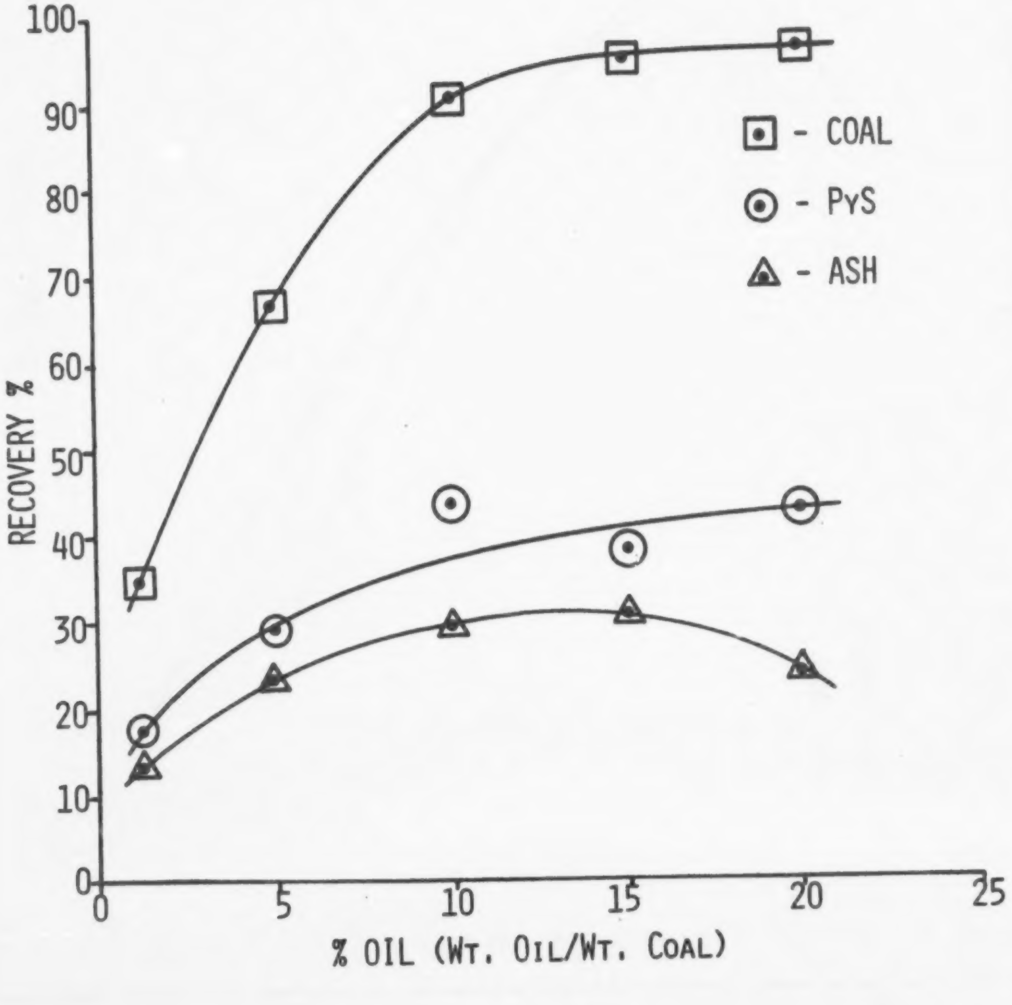


FIGURE 7

GENERALIZED
FLOWSHEET

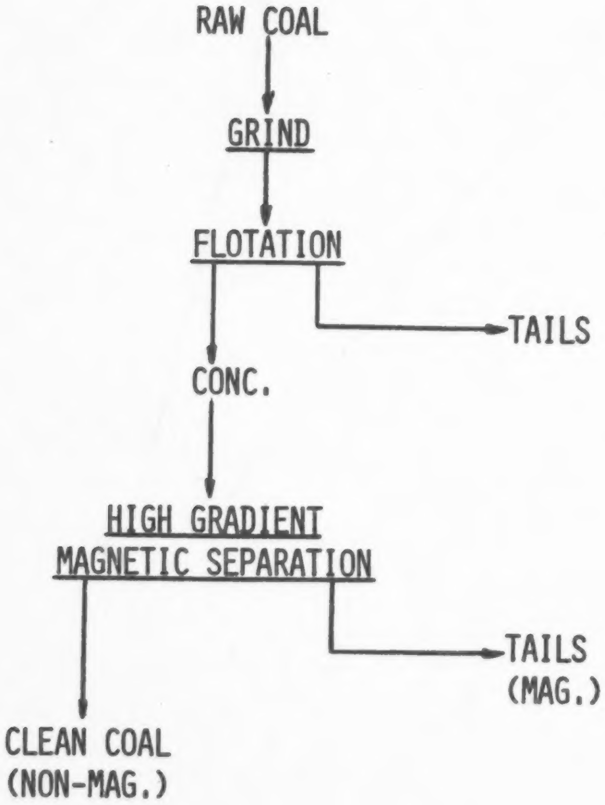

RAW COAL
GRIND
FLOTATION
TAILS
CONC.
HIGH GRADIENT MAGNETIC SEPARATION
TAILS (MAG.)
CLEAN COAL (NON-MAG.)

FIGURE 8. LABORATORY RESULTS
COMBINED FLOTATION - HGMS
ILLINOIS NO. 6 SEAM
-325 MESH

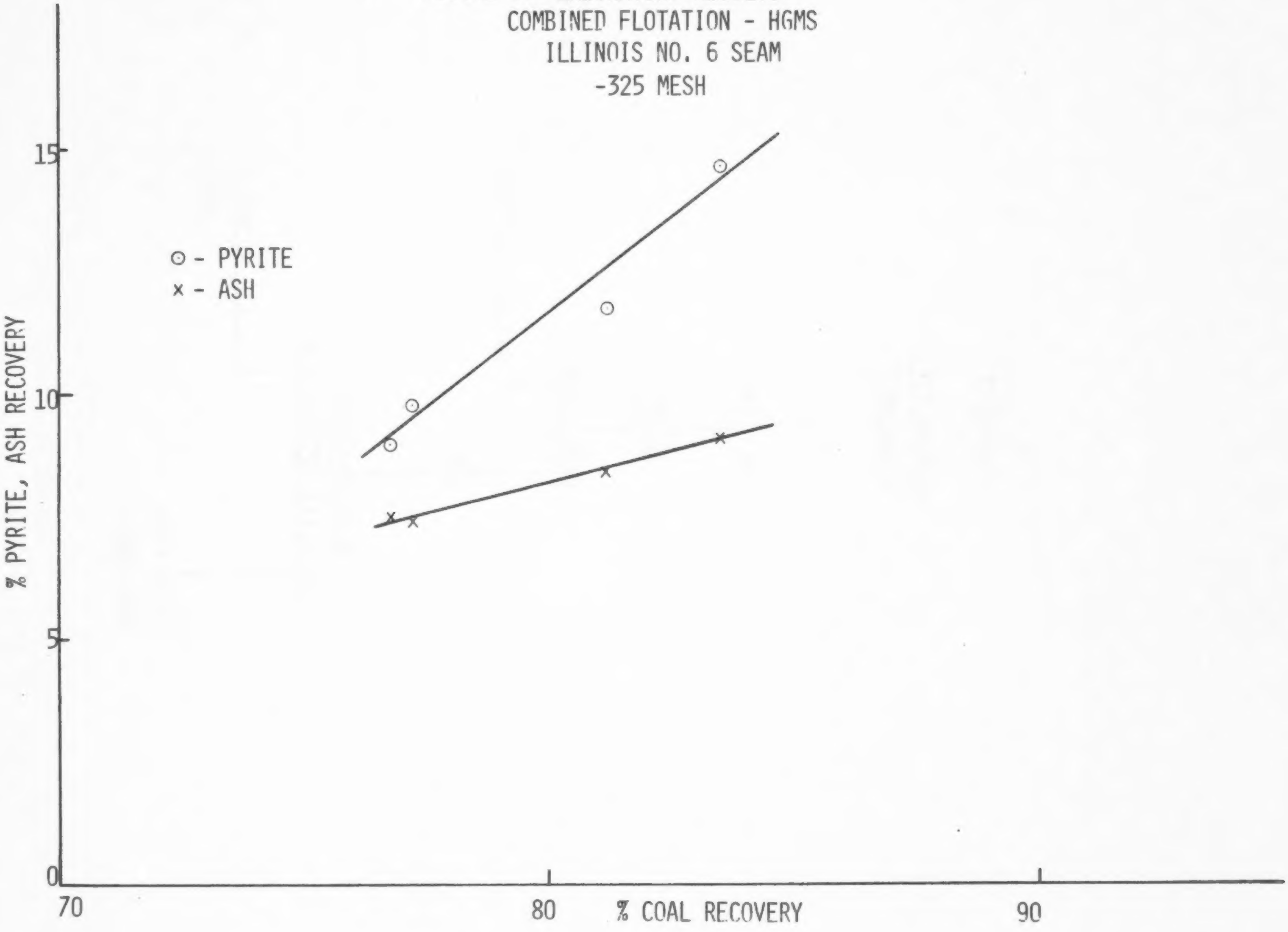


FIGURE 9

PILOT PLANT
FLOWSHEET A

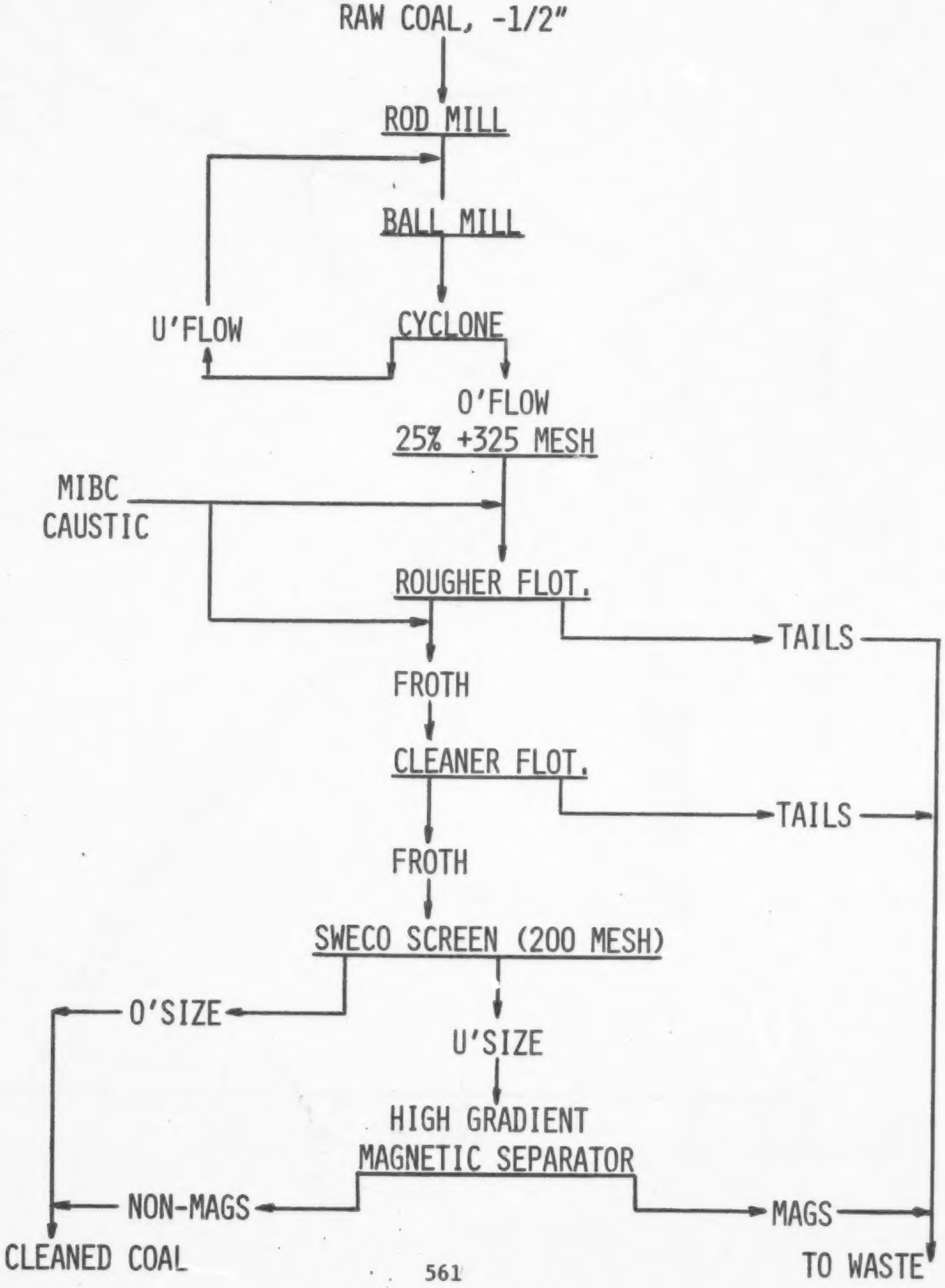

RAW COAL, -1/2"
ROD MILL
BALL MILL
U'FLOW
CYCLONE
O'FLOW
25% +325 MESH
MIBC
CAUSTIC
ROUGHER FLOT.
TAILS
FROTH
CLEANER FLOT.
TAILS
FROTH
SWECO SCREEN (200 MESH)
O'SIZE
U'SIZE
HIGH GRADIENT
MAGNETIC SEPARATOR
NON-MAGS
MAGS
CLEANED COAL
TO WASTE

FIGURE 10

SIZE DISTRIBUTIONS OF FINELY GROUND COAL

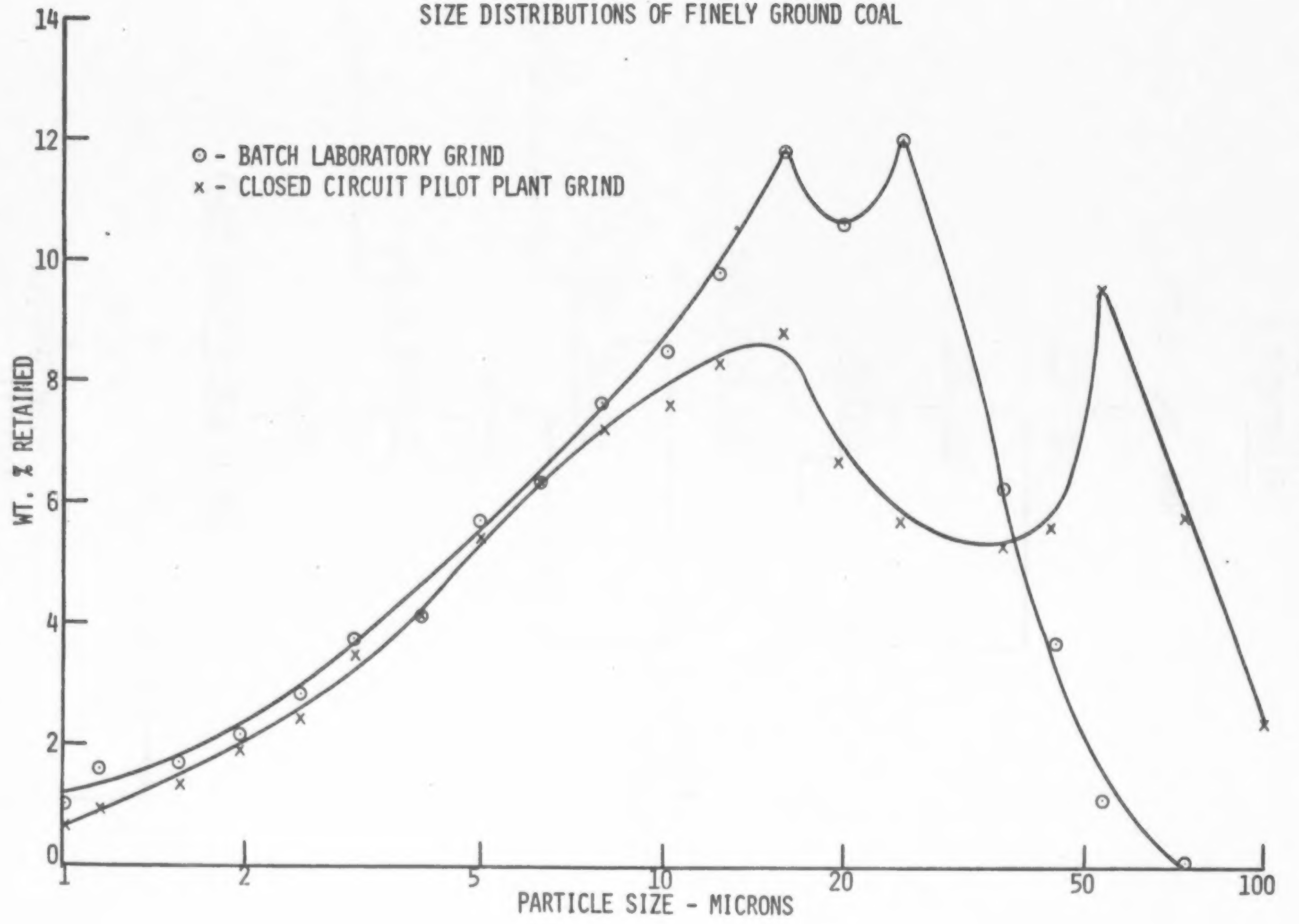


FIGURE 11

PILOT PLANT RESULTS ILLINOIS NO. 6 SEAM
FLOWSHEET A

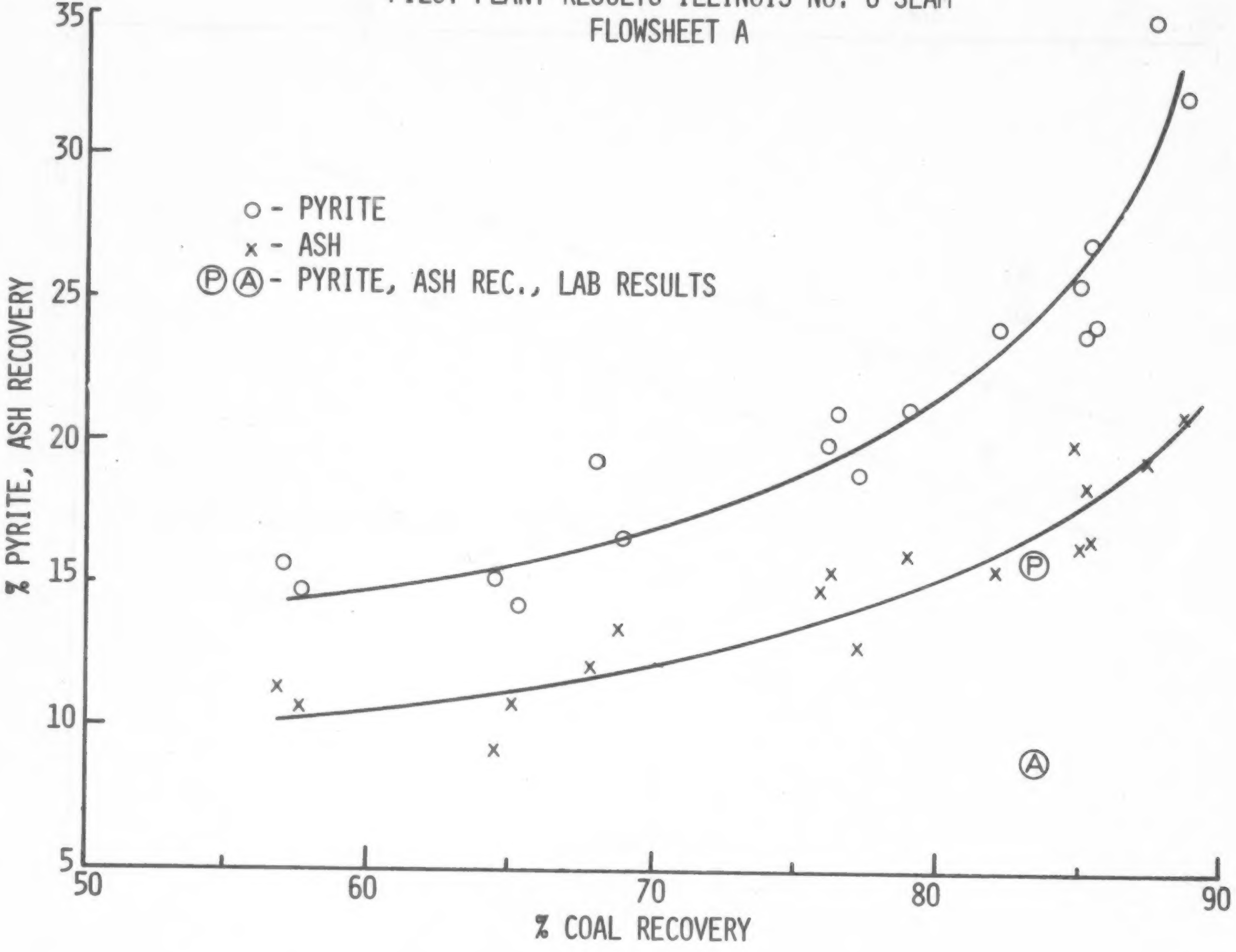


FIGURE 12

PILOT PLANT RESULTS
PITTSBURGH NO. 8 SEAM
FLOWSHEET A

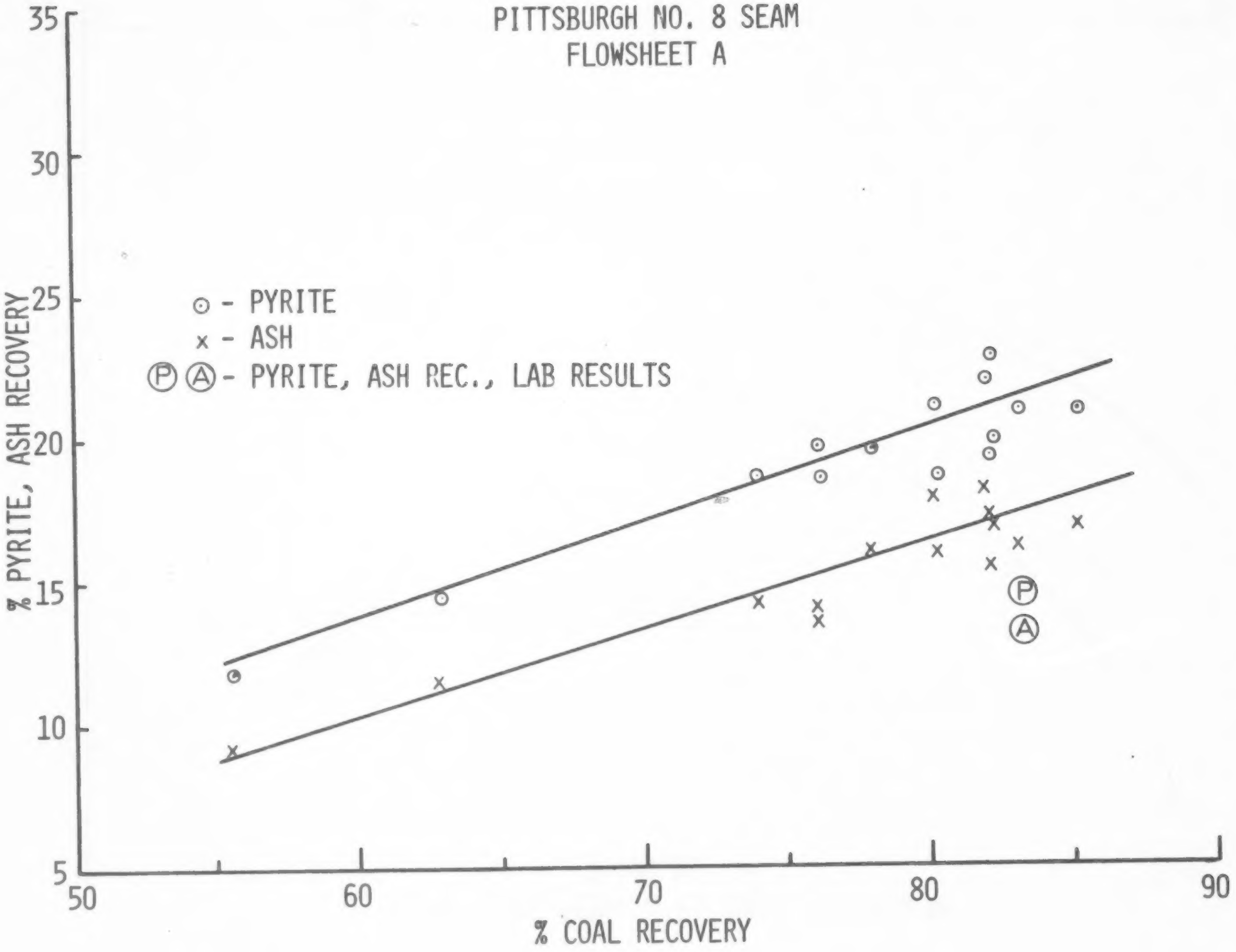


FIGURE 13

PILOT PLANT
FLOWSHEETS B&C

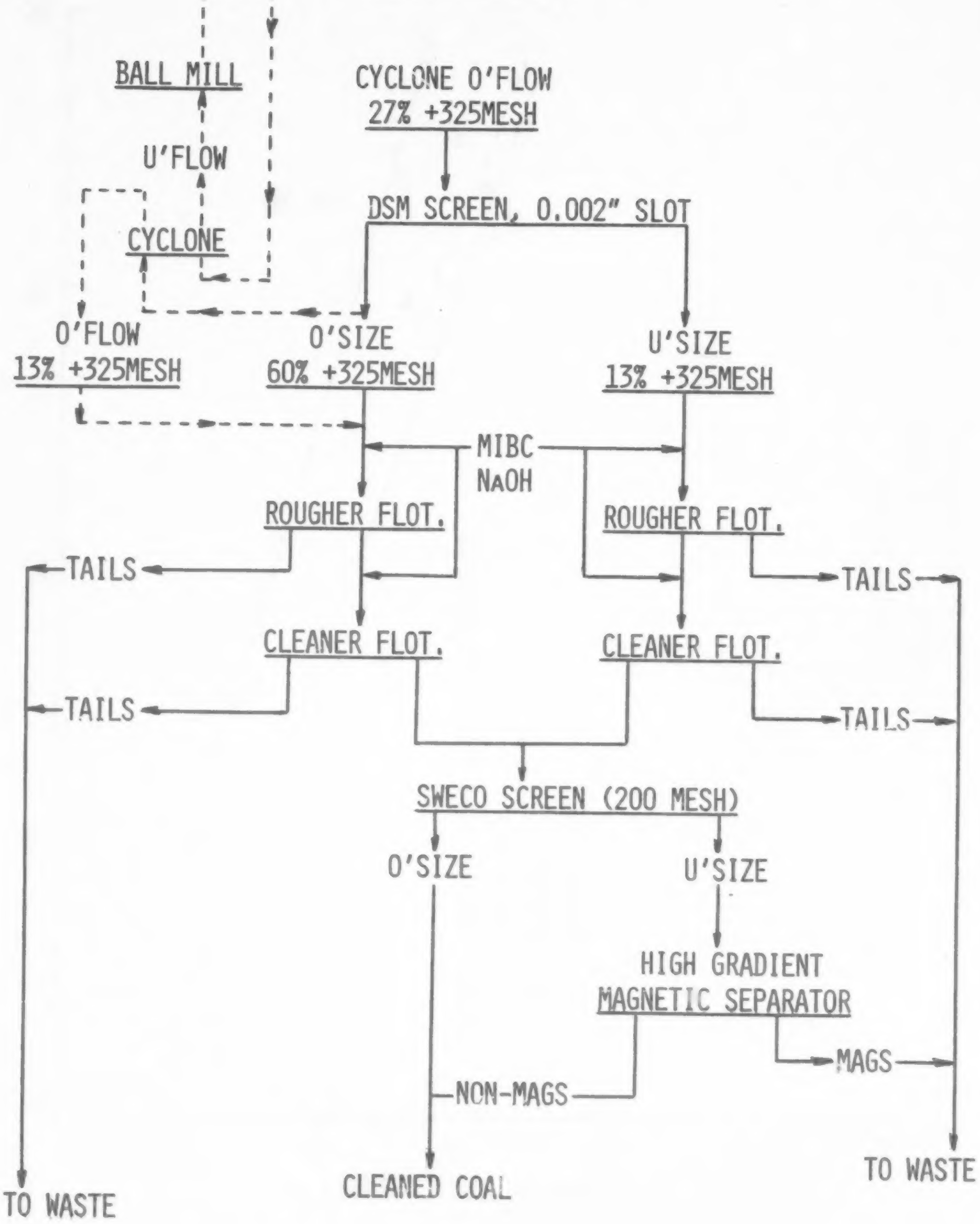

BALL MILL
CYCLONE O'FLOW
27% +325MESH
U'FLOW
DSM SCREEN, 0.002" SLOT
CYCLONE
O'FLOW
13% +325MESH
O'SIZE
60% +325MESH
U'SIZE
13% +325MESH
MIBC
NaOH
ROUGHER FLOT.
ROUGHER FLOT.
TAILS
TAILS
CLEANER FLOT.
CLEANER FLOT.
TAILS
TAILS
SWECO SCREEN (200 MESH)
O'SIZE
U'SIZE
HIGH GRADIENT
MAGNETIC SEPARATOR
MAGS
NON-MAGS
TO WASTE
CLEANED COAL
TO WASTE

FIGURE 14

PILOT PLANT RESULTS
PITTSBURGH NO. 8 SEAM
FLOWSHEETS B&C

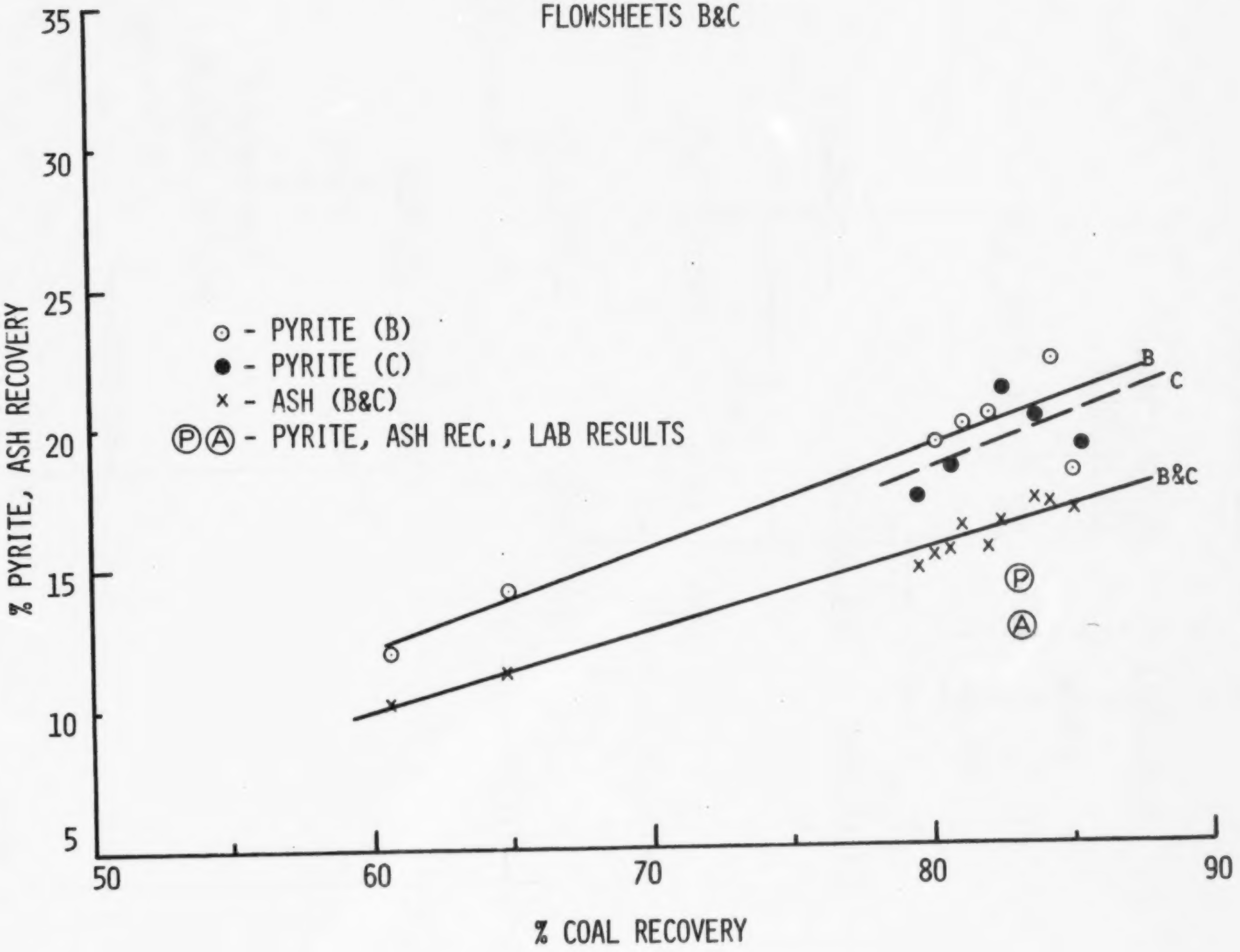
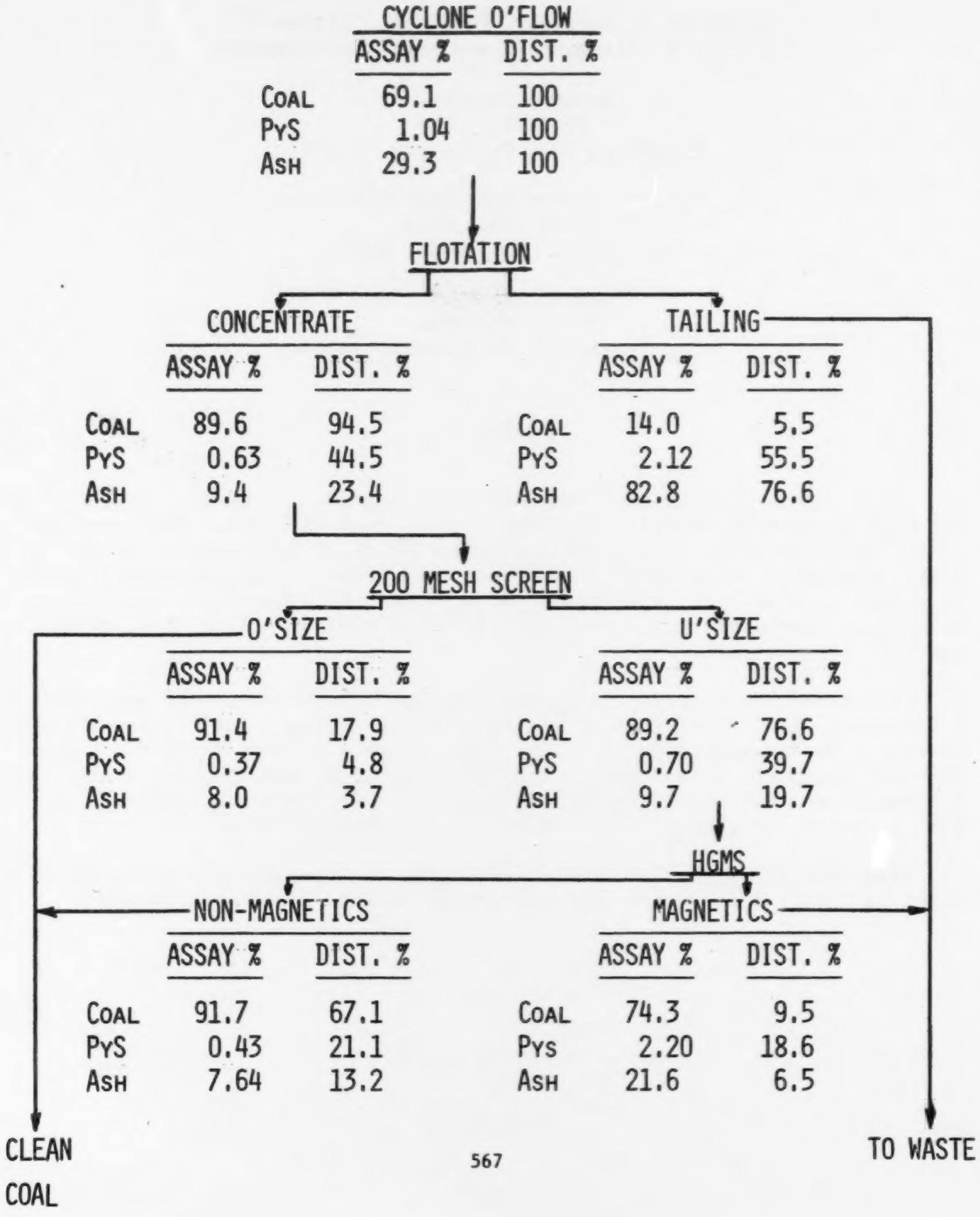


FIGURE 15
EXAMPLE OF PILOT PLANT
MATERIALS BALANCE-
ILLINOIS NO. 6 SEAM COAL


FLOTATION
200 MESH SCREEN
HGMS
CLEAN COAL
TO WASTE

CYCLONE O'FLOW

	ASSAY %	DIST. %
COAL	69.1	100
PYS	1.04	100
ASH	29.3	100

CONCENTRATE

	ASSAY %	DIST. %
COAL	89.6	94.5
PYS	0.63	44.5
ASH	9.4	23.4

TAILING

	ASSAY %	DIST. %
COAL	14.0	5.5
PYS	2.12	55.5
ASH	82.8	76.6

O'SIZE

	ASSAY %	DIST. %
COAL	91.4	17.9
PYS	0.37	4.8
ASH	8.0	3.7

U'SIZE

	ASSAY %	DIST. %
COAL	89.2	76.6
PYS	0.70	39.7
ASH	9.7	19.7

NON-MAGNETICS

	ASSAY %	DIST. %
COAL	91.7	67.1
PYS	0.43	21.1
ASH	7.64	13.2

MAGNETICS

	ASSAY %	DIST. %
COAL	74.3	9.5
PYS	2.20	18.6
ASH	21.6	6.5

THE POTENTIAL OF MAGNETIC SEPARATION IN COAL CLEANING

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ABSTRACT

This paper presents estimated costs for application of wet, high-gradient magnetic separation (HGMS) technology to fine coal cleaning. Coal pyritic sulfur and, commonly, an appreciable amount of other coal mineral matter is weakly magnetic. If pyritic sulfur and other magnetic mineral matter can be liberated by size reduction (minus 100 mesh or less), HGMS is a possible method for subsequent, efficient separation of coal from liberated, weakly magnetic impurities.

Presented in the paper is a possible flow scheme for use of wet, HGMS as a fine coal cleaning circuit in a plant cleaning coarser coal by conventional methods. Operations included in the flow scheme, in addition to HGMS, are wet coal grinding, clean coal mechanical dewatering, and coal refuse thickening. Estimated order-of-magnitude capital and operating costs are presented for wet, HGMS circuits designed to clean 75 to 310 tons/hour of coal.

Also briefly discussed are several types of HG magnetic separators which might be used for coal cleaning and current HGMS coal cleaning research.

High Gradient Magnetic Separation (HGMS) is a relatively new solids separation technology. It can be used to separate weakly magnetic, as well as strongly magnetic, solids down to extremely fine particle sizes – on the order of microns. Coal pyritic sulfur and, commonly, appreciable amounts of other coal mineral impurities are magnetically distinguishable from pure coal. (Coal pyrite and some other mineral impurities are paramagnetic while pure, organic coal is diamagnetic [Oder, 1976].) In many coals, both pyritic sulfur and other minerals are present as very fine, widely disseminated particles. Provided these impurities can be liberated through size reduction, HGMS offers a potential method for their subsequent, efficient separation from coal.

This paper presents one possible flow scheme for application of HGMS to fine coal cleaning. The scheme is strictly conceptual; but is based on coal HGMS research sponsored by the Electric Power Research Institute (EPRI).

HGMS BACKGROUND

HGMS is currently used commercially to beneficiate kaolin clay. High quality kaolin is used principally as filling and coating agents in the manufacture of paper products. In these applications its brightness is of major importance. To achieve required product quality, naturally occurring kaolin must be cleaned to remove mineral impurities called colorbodies. In many kaolin deposits, the colorbodies are very fine (some colorbodies are less than a micron in size), weakly magnetic minerals (anatase, rutile, iron pyrite, mica, etc.) which are present in dilute concentrations.

Kaolin can be cleaned by a variety of wet chemical leaching and physical cleaning processes. However, these processes are sufficiently complicated and expensive that the kaolin industry has expended considerable research effort to develop less expensive beneficiation methods. One relatively recent result of this research has been successful development of high-capacity, high gradient magnetic separators. These wet (water slurry) separators can remove colorbodies from kaolin typically classified to a size consist of 80 to 90 percent minus two microns with high kaolin recovery (Oder, 1976). The kaolin separators can be used alone to achieve modest color improvement or in combination with chemical leaching to produce high-grade kaolin which can compete with more expensive paper pigment materials.

The success of HGMS as a method for kaolin beneficiation and the high gradient magnetic separator designs which are responsible for this success are major reasons for emergence of HGMS as a new solids separation technology. Coal cleaning, with emphasis on desulfurization, is only one area where the feasibility of HGMS is currently being evaluated. Other areas include industrial and municipal wastewater treatment, beneficiation of oxidized taconite iron ores, removal of particulates from gas streams, uranium ore beneficiation, and biological separations.

Recent U.S. HGMS coal cleaning research has primarily been sponsored by the U.S. Bureau of Mines (USBM) before creation of the Department of Energy (DOE), DOE, and EPRI. USBM-DOE contract research has included (Hucko, 1978):

- A laboratory scale assessment by General Electric Company in conjunction with the Massachusetts Institute of Technology (MIT) and Eastern Associated Coal Corporation of the HGMS, wet and dry cleanability of a Pennsylvania Upper Freeport coal. (For separations performed on coal-water slurries, pyritic sulfur removals of 60 to 80 percent and ash removals of approximately 50 percent were achieved [Luborsky, 1977].)
- Laboratory assessment by the Naval Ordnance Station, Indian Head, Maryland of removal of pyritic sulfur by HGMS treatment of pulverized coal-oil slurries.
- Evaluation by MIT of the technical feasibility of using HGMS for recovery of magnetite from conventional, dense-medium coal cleaning circuits.

Currently, DOE is sponsoring evaluation of dry, HGMS, pulverized coal cleaning at Oak Ridge National Laboratory (ORNL) and wet, HGMS coal cleaning at Michigan Technological University. An initial phase of the ORNL evaluation included benchscale testing of a high gradient magnetic separator concept in which a fluidized bed is created within a separator. This testing was performed for ORNL by Auburn University. The work being performed at Michigan Technological University involves pilot-scale evaluation of combined froth flotation and HGMS for fine coal cleaning (Freyberger, 1978). DOE is, also, at its Bruceton, Pennsylvania Research Center performing a comparison of wet HGMS and two stage coal—pyrite flotation for cleaning of minus 35 mesh coal (Hucko, 1978).

EPRI's magnetic coal cleaning evaluation program involves processes which use HGMS and conventional, high intensity magnetic separation. It consists of the following five contracts:

- Sala Magnetics Incorporated – Wet, HGMS benchscale and pilot-scale testing of five Appalachia coals using iron enclosed, high gradient magnetic separators
- Magnetic Corporation of America (MCA) – Wet and dry HGMS benchscale testing of a Pennsylvania Upper Freeport seam coal and an Ohio Illinois No. 6 seam coal using a superconducting, high gradient magnetic separator

- Colorado School of Mines Research Institute (CSMRI) – Benchscale research on the technical feasibility of using aqueous and organic base magnetic fluids to preferentially increase the magnetic susceptability of either coal mineral matter or pure coal. High gradient magnetic separators were used to perform coal-mineral matter separations following magnetic enhancement of either coal or mineral matter.
- Bechtel National, Inc. - Development of comparable, commercial conceptual designs for HGMS coal cleaning plants based on the coal HGMS tests performed for EPRI by Sala Magnetics and MCA. The Bechtel contract, also, includes preparation of capital and operating cost estimates for these two HGMS coal cleaning plants and comparison of these estimated costs with those for a conceptual, conventional, commercial coal cleaning plant. (The HGMS fine coal cleaning circuit conceptual design presented in this paper is based on the HGMS, coal cleaning plant, conceptual designs being developed for EPRI.)

- Nedlog Technology Group – Evaluation of conventional, induced roll, high intensity magnetic separators for use in the Magnex℠ Process. The Magnex℠ Process, invented at Hazen Research Incorporated and being developed by Nedlog Technology (Porter, et al., 1978), treats coal with iron carbonyl to significantly enhance the magnetic susceptibility of both coal pyrite and other mineral matter relative to pure coal.

All five EPRI magnetic coal cleaning contracts are currently nearing completion. Final reports should be available at the end of 1978 or early in 1979.

HIGH GRADIENT MAGNETIC SEPARATOR DESIGNS

A large number of different magnetic separator designs, built and proposed, are referred to as high gradient magnetic separators (Iannicelli, 1976). However, only three high gradient designs are briefly described in this paper. These designs represent those used commercially for kaolin beneficiation and by Sala Magnetics and MCA in their coal cleaning evaluations. All three designs generate high gradient magnetic fields through use of magnetic stainless steel matrices. The magnetic gradients actually produced in these separators are normally well in excess of 1,000 kilogauss per centimeter.

Actual gradient magnitudes depend on both separator magnet design and matrix design.

Figure 1 shows the main components for the type of wet, HG magnetic separator currently used in the kaolin industry and used by Sala Magnetics in their benchscale coal tests. It consists of a solenoid electromagnet completely enclosed in an iron box. The box provides a return circuit for the magnetic flux generated by the electromagnetic coils. Small pipe penetrations in the box top and bottom permit transport of slurry in and out of the solenoid cavity. This cavity is lined with a thin wall canister inside of which is packed fine, ferromagnetic stainless steel wool. When the electromagnet is energized, high magnetic gradients are induced on the individual wool matrix filaments. Strong and weakly-magnetic particles passing through the **matrix** are, due to the magnetic gradients around the filaments, attracted to and captured on the filament surfaces. Actual volume of the separator canister occupied by matrix filaments is quite small; usually less than

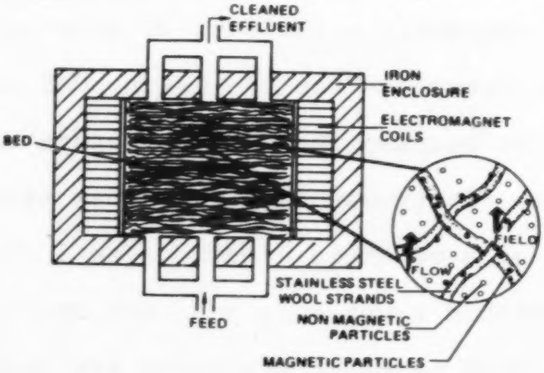

CLEANED EFFLUENT
IRON ENCLOSURE
ELECTROMAGNET COILS
BED
FIELD
FLOW
STAINLESS STEEL WOOL STRANDS
FEED
NON MAGNETIC PARTICLES
MAGNETIC PARTICLES

Figure 1. Vertical Section through the Center of a Batch (Cyclic), Wet High Gradient Magnetic Separator

5 percent. Because of this, comparatively high feed rates at low-pressure drops can be achieved with this separator design. Captured magnetic particles are removed from the separator by deenergizing the magnet and flushing. This cleaning method works well for applications, such as kaolin beneficiation, where the magnetic solids in the separator feed are present in low concentrations. For processing of solids in which the fraction of magnetics present is appreciable, such as in coal, a continuous rather than a batch (cyclic) separator is required. Cycle times for batch separation of coal would be so short that numerous batch, HGMS separators would be required.

Figure 2 shows a continuous operation, commercial, wet, high gradient magnetic separator manufactured by Sala Magnetics. (For a discussion of the development of this separator, see Arvidson, et al., 1976.) This is the type of separator used by Sala Magnetics in their EPRI pilot-scale, coal cleaning tests. And, it is similar to the separator used in the HGMS fine coal cleaning circuit presented later in this paper. The basic operating principles of this separator are identical to those described for the batch HGMS separator. However, the capture matrix, the ring structure in Figure 2, revolves through an electromagnet rather than remaining stationary inside of a solenoid electromagnet. When a section of the matrix is within a magnetic head (an individual electromagnet assembly), high magnetic gradients are induced around its surfaces and magnetic particles are captured. When the matrix moves out of a magnetic head, the induced magnet gradients rapidly decay and captured magnetics are flushed from the matrix. In order to remove mechanically entrained non-magnetic particles, a rinse is applied before the matrix exits a magnetic head, i.e., while the magnetic capture forces are still present. Clear water is, usually, used for both matrix flushing and rinsing. Matrix revolution rate is on the order of 1 rpm.

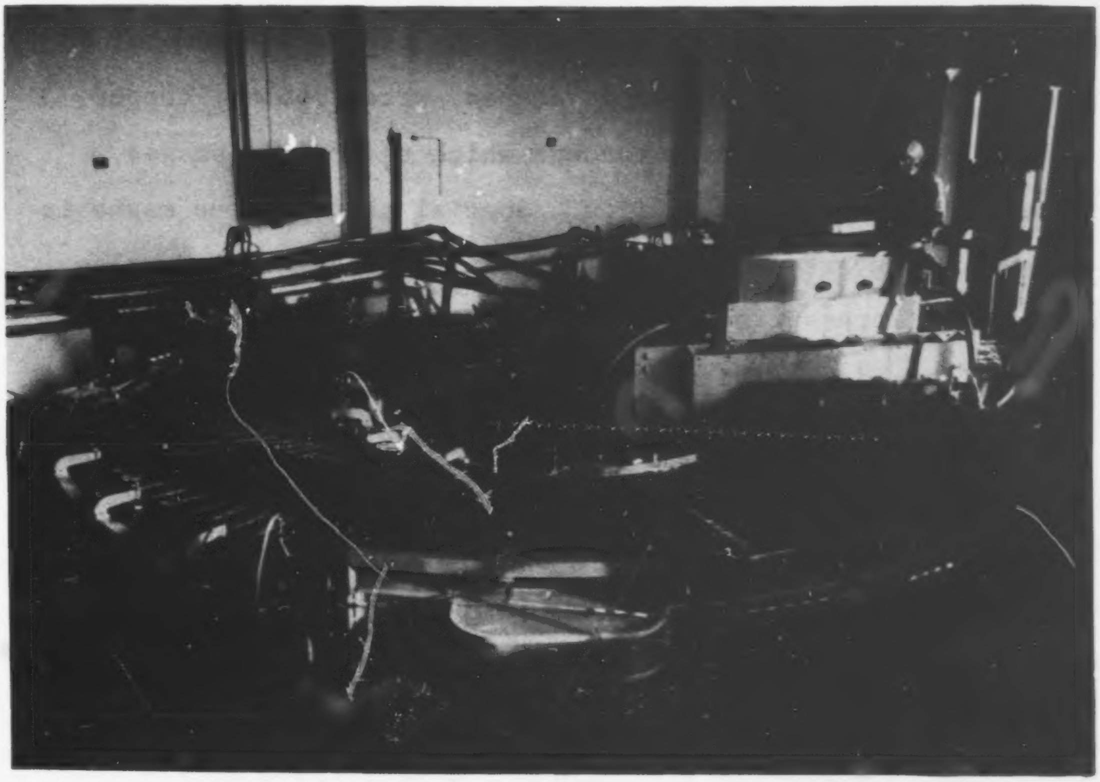


Figure 2. Sala Magnetics Incorporated Carousel, Continuous High Gradient Magnetic Separator

The carousel separator design shown in Figure 2 is built with multiple magnetic heads when required separation rates exceed the capability of a single head. A wide variety of matrix designs can be used with this separator. Usually, these are fabricated using various sizes of ferromagnetic stainless steel wool or some form of crimped or otherwise formed ferrogmagnetic, stainless steel, expanded metal. Actual selection of a matrix material and its configuration depends on separation application. Electromagnets used in the carousel separator consist of double, saddle wedge shaped, water cooled, copper coils. Except at the ends through which the matrix passes, these coils are encased by iron. Special seals at the magnetic head open ends are used to control slurry leakage. They also allow use of pressurized water for matrix rinsing and flushing.

A third high gradient magnetic separator design that uses a capture matrix is one which employs a superconducting magnet for generation of high intensity magnetic fields. A bench-scale, cyclic version of such a separator was used by MCA in the HGMS coal cleaning tests they performed for EPRI. The matrix used in these tests was magnetic, stainless steel wool.

Currently, MCA is developing a commercial scale, superconducting, HG magnetic separator. The collection matrix for this separator consists of multiple, linearly connected sections.

These sections reciprocate in and out of a cylindrical superconducting magnet. When a matrix section within the magnet becomes fully loaded, it is pushed or pulled out and another takes its place. After leaving the magnet, fully loaded matrix sections move into an iron magnetic shield which results in reduction of the magnetic field gradients in the matrix to nearly zero values. The sections are then water flushed, after which, they are ready for reinsertion into the magnet.

To achieve and maintain the temperature (4.2°K) required for operation of a superconducting magnet, liquid helium is required for coil cooling. Liquid nitrogen may, also, be required for operation of the helium refrigeration system. Handling and storage of both liquid helium and nitrogen would be new to the coal cleaning industry.

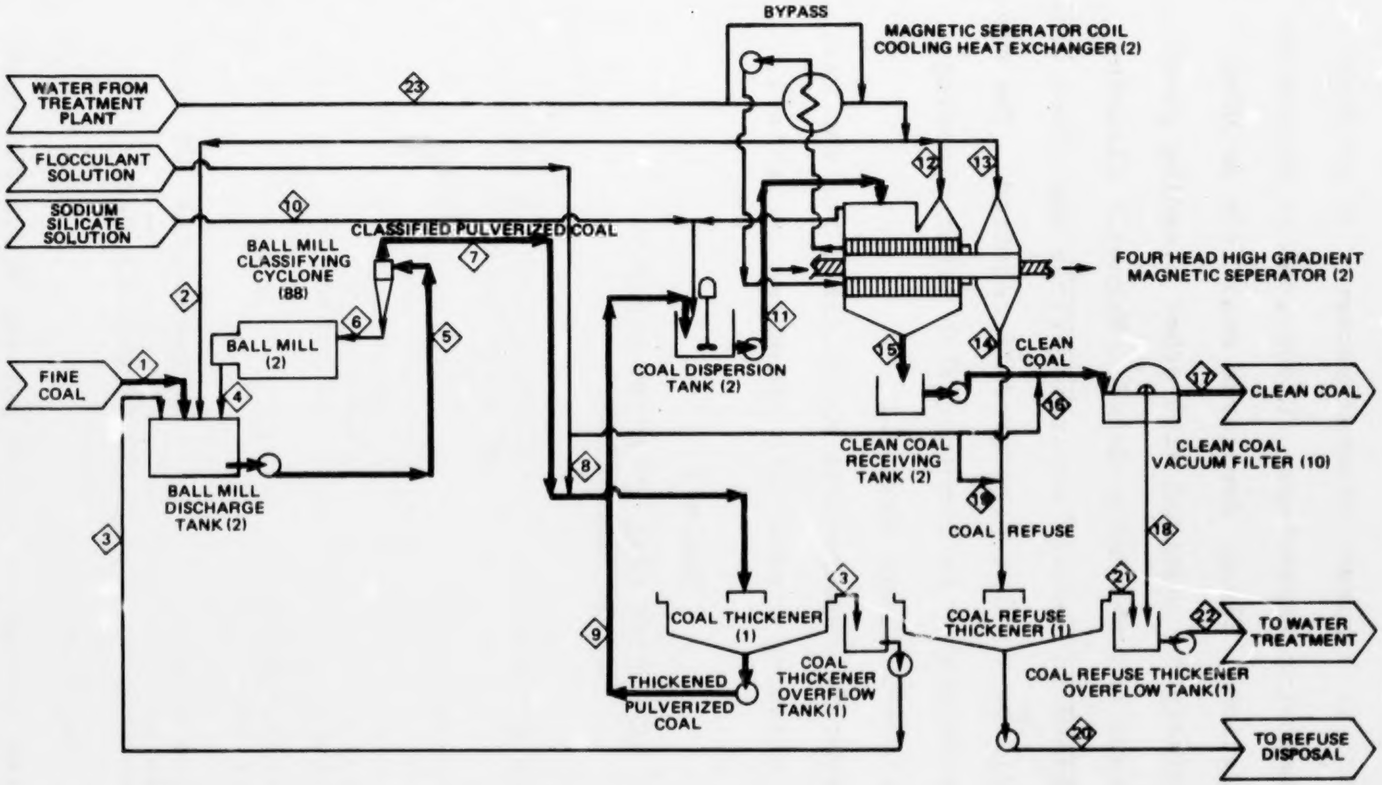
Potential advantages of a superconducting, HG magnetic separator compared with those which use iron enclosed electromagnets are use of considerably higher magnetic fields and reduced power consumption. The higher magnetic fields (on the order of 50 kilogauss) which can be generated by superconducting magnets can be used to (Stekly, 1975):

- Separate more weakly magnetic or finer particles
- Obtain performance comparable to lower field strengths but at increased feed rates
- Increase matrix loading

Power consumption may be lower for superconducting magnetics because essentially zero power is required to generate the magnetic field. Significant amounts are, however, required for operation of the magnet refrigeration system. The real advantages of large superconducting, HG magnetic separators will only become fully apparent after one is actually constructed and operated.

WET, HIGH GRADIENT MAGNETIC SEPARATION FINE COAL CLEANING CIRCUIT DESCRIPTION

Figure 3 presents a conceptual flow scheme and a design material balance for application of wet HGMS to fine coal cleaning. (Numbers in parenthesis after the equipment titles are the number of actual pieces required of a specific equipment type.) For actual use, this fine coal cleaning circuit would be combined with other cleaning circuits and various coal handling-processing operations (crushing, conveying, thickening, dewatering, drying, storage, etc.) to form a complete coal cleaning plant. Coal cleaned in the HGMS circuit could come from a coarse cleaning circuit, a conventional fine cleaning circuit, or, possible, from a size reduction operation. The circuit could be used to replace or supplement such conventional fine coal cleaning methods as fine heavy media cyclones, water cyclones, and froth flotation.


BYPASS
MAGNETIC SEPERATOR COIL COOLING HEAT EXCHANGER (2)
WATER FROM TREATMENT PLANT
FLOCCULANT SOLUTION
SODIUM SILICATE SOLUTION
FINE COAL
BALL MILL CLASSIFYING CYCLONE (88)
CLASSIFIED PULVERIZED COAL
BALL MILL (2)
BALL MILL DISCHARGE TANK (2)
COAL DISPERSION TANK (2)
FOUR HEAD HIGH GRADIENT MAGNETIC SEPERATOR (2)
CLEAN COAL
CLEAN COAL
CLEAN COAL RECEIVING TANK (2)
CLEAN COAL VACUUM FILTER (10)
COAL REFUSE
COAL THICKENER (1)
THICKENED PULVERIZED COAL
COAL THICKENER OVERFLOW TANK(1)
COAL REFUSE THICKENER (1)
COAL REFUSE THICKENER OVERFLOW TANK(1)
TO WATER TREATMENT
TO REFUSE DISPOSAL
1
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STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
SOLIDS FLOW – TONS/HOUR	310	–	–	465	775	465	310	–	310	–	310	–	–	46.5	263.5	–	263.5	–	–	46.5	–	–	–
TOTAL FLOW – TONS/HOUR	365	666.75	2,973.25	1,162	5,167	1,162	4,005	1.25	1,033	2.5	1,035.5	708.25	708.25	1,226.5	1,225.5	1	366	860.5	0.2	132	1,094.7	1,955.2	2,083.25
TOTAL FLOW – GALLONS/MINUTE	–	2,667	11,893	4,098	19,751	4,098	15,653	5	3,765	10	3,775	2,833	2,833	4,823	4,618	4	1,180	3,442	0.8	449	4,375	7,817	8,333
SOLIDS CONCENTRATION – WT. PERCENT	85	–	–	40	15	40	7.7	–	30	–	29.94	–	–	3.79	21.5	–	72	–	–	35	–	–	–

Figure 3. WET HGMS FINE COAL CLEANING CIRCUIT CONCEPTUAL FLOW SCHEME

In the HGMS circuit, coal is initially ground wet to a fine size consist to liberate mineral matter. It is then cleaned in HG magnetic separators. Clean coal is dewatered by vacuum filtration. Clean, dewatered coal from an HGMS circuit would likely be combined with other cleaning plant clean coal streams and thermally dried. Magnetic cleaning refuse is thickened to recover separator rinse and flush water. This refuse could be further dewatered if required. The magnetic refuse would likely be combined with other cleaning plant refuse before ultimate disposal.

Design operating requirements established for the wet, HGMS fine coal cleaning circuit are presented in Table 1.

Table 1

WET HGMS FINE COAL CLEANING CIRCUIT DESIGN REQUIREMENTS

Circuit Design Capacity	310 tons/hour of coal on a dry basis
Feed Coal Conditions	
Source	Appalachia
Size Consist	14 mesh x 0
Total Moisture	15 wt percent
HG Magnetic Separator Feed Conditions	
Coal Size Consist	70 percent minus 200 mesh
Coal Slurry Concentration	30 wt percent coal
Clean Coal Requirements	
Coal Size Consist	70 percent minus 200 mesh
Coal Moisture	28-35 wt percent

The design, dry coal circuit feed rate, 310 tons per hour, is identical to that for complete, HGMS, conceptual, coal cleaning plant designs being developed for EPRI. The HG magnetic separator feed conditions result from the HGMS coal cleaning tests performed by Sala Magnetics and MCA.

Fine Coal Grinding

Two basic approaches were considered for grinding coal to 70 percent minus 200 mesh, an unprecedented size consist for coal cleaning: dry and wet grinding. Dry coal grinding (pulverizing) is a well established technology. All pulverized coal required for utility power plant steam generators, large industrial steam generators, and many other coal-fired processes is pulverized in dry coal mills. As far as known, wet coal pulverizing has never been used in any large scale, commercial operation. There simply has never been any requirement for large scale, wet coal pulverizing. Large scale, wet grinding, however, is widely used in mineral ore beneficiation operations.

Despite the fact that dry coal grinding is a well developed technology compared with wet grinding, wet grinding was selected for the conceptual, wet, HGMS fine coal cleaning circuit. The main reason for this selection is that for a wet process, wet grinding is believed to be considerably less expensive than dry grinding. This conclusion is based on considerable experience in design of large scale, dry, coal grinding facilities for conceptual, commercial coal conversion plants (Bechtel, 1977 and Karlson, et al., 1978).

Coal fed to the HGMS fine coal cleaning circuit is first slurried with water in two grinding mill discharge tanks; one tank per grinding train (see Figure 3). It is then pumped to a series of parallel, 10-inch-diameter cyclones for size classification. These cyclones are designed to product an overflow containing 70 percent minus 200 mesh coal. Oversize coal from the cyclones, the underflow stream, flows by gravity to two ball mills for wet grinding. Coal slurry exiting the ball mills returns by gravity to the mill discharge tanks where it mixes with the feed coal. From here it is pumped to the classifying cyclones. Each of the two wet grinding mills selected for the HGMS cleaning circuit has a nominal diameter of 16 feet and is 27 feet long. Each mill is equipped with a 4,500-hp drive.

In order to produce coal sized to 70 percent minus 200 mesh, the classifying cyclones must be fed a slurry containing on the order of 15 wt percent coal. If these cyclones are fed slurry containing a significantly higher coal concentration, classification will deteriorate and large quantities of oversize coal will be misplaced into the overflow. Also, excessive minus 200 mesh coal will be misplaced to the underflow and be overground. The 15 wt percent cyclone coal feed concentration limit is only an estimate. As far as could be determined, coal ground to 70 percent minus 200 mesh has never been classified in commercial scale cyclones. Through development work it may be possible to increase the limiting cyclone feed concentration somewhat.

For a feed coal concentration of 15 wt percent, the overflow (sized coal) from the classifying cyclones will have an estimated coal concentration of 8 wt percent coal. This concentration is considerably lower than those proposed by both Sala Magnetics and MCA for wet, HGMS coal cleaning; 30-35 wt percent coal. To achieve coal slurry concentrations in this range, thickening is required.

As for efficient classification of coal at 70 percent minus 200 mesh, no performance data was found for thickening of coal this fine. Therefore, as part of the EPRI HGMS coal cleaning evaluation program, a series of coal thickening tests were performed by Envirotech Corporation. Pulverized coal used in these thickening tests was an Eastern bituminous coal provided by TVA. It was collected from a power plant steam generator coal mill.

The HGMS fine coal cleaning circuit thickener design is a direct result of the Envirotech thickening tests. Design thickener loading is 3 square feet/ton-day. This results in a single 175-foot-diameter thickener. To achieve the design loading, use of an anionic flocculant is required. Design flocculant addition rate is 0.02 pounds/ton of dry coal.

Wet HGMS Coal Cleaning

Before pulverized coal is fed to HG magnetic separators, it is treated with a dispersant. The dispersant used in the Figure 3 flow scheme is sodium silicate. Design addition rate is 1.8 pounds/ton of dry coal. Sodium silicate is received in rail cars as anhydrous briquettes. These briquettes are dissolved in a pressure dissolver using steam. Dissolved sodium silicate is fed to the coal dispersion tanks as a 10 wt percent solution.

The conceptual, HGMS, fine coal cleaning circuit uses a new, continuous HG magnetic separator being developed by Sala Magnetics. This separator is similar to the one shown in Figure 2. In the new design, however, the capture matrix is a narrow width, segmented belt rather than a ring. This continuous belt matrix is driven by sprockets or rollers located at its ends. In side view the arrangement is similar to that of a metal tractor tread. Magnetic heads, similar in design to the head shown in Figure 2, are mounted along the top and bottom of the matrix belt. Matrix belt width is approximately 5.25 feet.

Two of the new, Sala Magnetics' linear type, HG magnetic separators are required to clean, with some spare capacity, 310 tons/hour of dry coal as a 30 wt percent slurry. Each separator has four magnetic heads, is approximately 25 feet high, and 43 feet long. Power requirement of each magnetic head is 250 kW.

As shown in the Figure 3 material balance, substantial quantities of water are required for both matrix rinsing and flushing; 2,833 gallons per minute for each operation. Approximately one-third of the rinse water reports to the clean coal product. The remainder is combined with the flush water.

For the design material balance, a clean coal weight recovery of 85 percent was assumed. This is consistent with results obtained by Sala Magnetics in pilot tests using coal that had been cleaned at a specific gravity of 1.6. Recoveries obtained by Sala Magnetics, MCA, and CSMRI on uncleaned, Eastern bituminous coals were, however, usually less than 85 percent. Coal weight and Btu recoveries, as well as, coal sulfur and ash removals, were found to be very dependent on the coal, coal size consist, separator matrix design, and separator operating conditions. A considerable amount of additional test work is required to establish for even selected coals the limits to which they can be cleaned by HGMS and at what recoveries.

Clean Coal Dewatering

After HGMS, clean coal is dewatered with vacuum filters. Vacuum filtration of 70 percent minus 200 mesh coal, like its classification and thickening, is an area where only limited design information is available. As a result, a cursory evaluation of pulverized coal filtration was performed for EPRI by Envirotech.

In the filtration tests, the coal sample used for the thickening tests was thickened using a flocculant, treated with sodium silicate dispersant, agitated, and then filtered using standard leaf filtration test procedures. Figure 4 summarizes the results of these filtration tests. A minimum surface moisture of 25 wt percent was achieved at a filtration rate of 20 pounds/hour-square foot. Further, the curve presented in Figure 4 shows that cake surface moisture concentration is relatively insensitive to filtration rate. A doubling of the filtration rate from 20 to 40 pounds/hour-square foot causes surface moisture to increase to only 27.5 wt percent.

Table 2 presents design data established for the wet, HGMS fine coal cleaning circuit filtration operation. Application of this design data results in a filtration system which consists of 10 disc filters. Each unit has 15 discs which are 12.5 feet in diameter. Total filtration area is 33,000 square feet.

Filter cake is collected on two belt conveyors. The discharge ends of these conveyors is the clean coal outlet boundary of the HGMS fine coal cleaning circuit. From here clean coal would likely be dried or agglomerated and then dried.

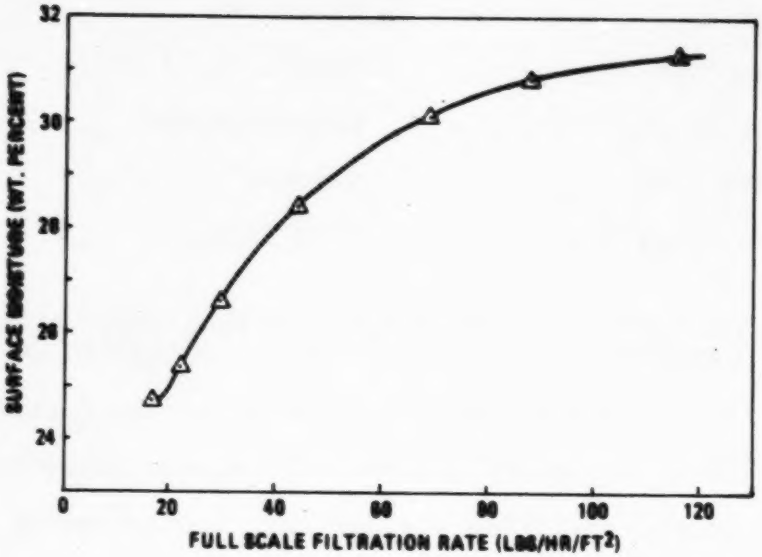

Figure 4. Effect of Filtration Rate on Coal Surface Moisture

Table 2

WET HGMS FINE COAL CLEANING CIRCUIT FILTRATION OPERATION DESIGN DATA

Feed Coal Concentration	20 wt percent
Minimum Surface Moisture	25 wt percent
Design Filtration Rate	20 $lb/hr\text{-}ft^2$
Estimated Filtrate Solids	Less than 0.5 wt percent
Vacuum	22 in. HG
Filter Type	Disc
Filter Cloth	Polypropylene
Polymer Type	Anionic
Polymer Dose	0.02 lb/ton

WET, HIGH GRADIENT MAGNETIC SEPARATION FINE COAL CLEANING CIRCUIT ESTIMATED ORDER-OF-MAGNITUDE CAPITAL AND OPERATING COSTS

Order-of-magnitude capital and mean annual operating costs have been estimated for the flow scheme presented in Figure 3. These estimates are derived from estimates developed for EPRI for complete, conceptual, HGMS coal cleaning plants. The EPRI estimates were developed to determine general cost levels for application of HGMS to pulverized coal cleaning and to identify cost sensitive HGMS cleaning operations. The estimates presented in this paper, as well as those developed for EPRI represent an attempt to project possible economics for wet, HGMS coal cleaning for the purpose of planning future development programs. In using these cost estimates it should be recognized that application of HGMS to coal cleaning is new. Indeed, consideration of cleaning coal purposely ground to 200 mesh or finer is new.

Order-of-Magnitude Capital Cost Estimate

Table 3 presents an estimated order-of-magnitude capital cost. Estimated total capital cost including indirect costs and an allowance for owners' costs is $44.95 million. The estimate is based on:

- The conceptual process flow scheme presented in Figure 3
- Order-of-magnitude quotations for major equipment from manufacturers
- Actual cost information for relevant, completed Bechtel projects
- A major equipment list
- Major motor and HG magnetic separator power requirements
- Estimated building volumes

At the direct cost level ($30.62 million), 25.7 percent is associated with coal grinding and 74.3 percent with HGMS coal cleaning, clean coal dewatering, and refuse thickening. Estimated cost of the HG magnetic separators was provided by Sala Magnetics. Their estimated cost for a complete, HG magnetic separator facility is $11.0 million. This cost includes equipment (two 4-head HG magnetic separators, separator drives,

Table 3

ESTIMATED ORDER-OF-MAGNITUDE CAPITAL COST
WET HIGH GRADIENT MAGNETIC SEPARATION FINE COAL CLEANING CIRCUIT
(All Costs Are For Mid-1978 In Thousands Of Dollars)

	Coal Grinding Operation	Coal HGMS and Filtration Operation	Total	Percent of Total
DIRECT COSTS				
Mechanical Equipment	4,520	14,850	19,370	43.1%
Piping and Instrumentation	660	1,880	2,540	5.6%
Electrical	1,850	4,490	6,340	14.1%
Civil and Architectural	850	1,520	2,370	5.3%
Direct Cost Subtotal	7,880	22,740	30,620	68.1%
Percent of Direct Cost	25.7%	74.3%	100.0%	
INDIRECT COSTS				
Engineering, Project Services, and Fees			5,760	12.8%
Spare Parts			330	0.7%
Sales Taxes			730	1.6%
Contingency			5,370	12.0%
CONSTRUCTED COST SUBTOTAL			42,810	95.2%
Allowance for Owners' Costs			2,140	4.8%
TOTAL CAPITAL COST			44,950	100.0%

a d.c. power supply system, a closed-circuit magnet cooling system, controls, and some separator piping), equipment installation, and startup services. The cost for the complete magnetic separator facility was treated as a subcontract. It is part of $14.85 million estimated for mechanical equipment required by the coal HGMS and filtration operation.

Design coal feed capacity for the HGMS cleaning circuit is 310 tons of dry coal/hour. Therefore, on an hourly feed capacity basis, estimated total capital cost is $145,000 per ton per hour of feed coal. This is considerably higher than the unit cost for any conventional coal cleaning circuit or complete plant. However, most conventional circuits clean much coarser coal. Because of this difference, any comparison of costs for conventional circuits and circuits which clean pulverized coal should consider the final form in which the clean coal is used. If the final form is pulverized coal, a cost credit should be assigned to a pulverized coal cleaning circuit to account for the fact that no or only limited additional coal pulverizing is required before coal use.

To determine the approximate effect of circuit design feed rate on estimated capital cost, the Table 3 estimate was used to factor very approximate capital cost estimates for circuits having design feed capacities of 155 and 75 tons of dry coal per hour. These estimates were used to calculate an exponential design capacity-capital cost scale factor. The estimated value of this exponential scale factor is 0.8.

Order-of-Magnitude Operating Cost Estimate

Estimated order-of-magnitude mean annual operating costs for the wet, HGMS fine coal cleaning circuit are presented in Table 4. Total estimated mean annual operating cost is $6.37 million including depreciation and $4.23 million excluding depreciation. On an annual dry, coal feed rate basis (1.008 million tons per year), estimated total annual operating cost is $6.32 per design annual ton including depreciation and $4.20 per design annual ton excluding depreciation.

The term mean annual operating cost is used to imply that the operating costs are mean annual estimates for a 20-year coal cleaning plant life. Ideally, multiplication of these estimates by 20 results in an estimate of all operating costs, excluding working capital, which would be incurred over the entire 20-year plant life. Actual operating costs for a specific year could differ significantly from the mean annual estimate. Some operating costs components, such as major maintenance subcontracts, are not incurred every year of plant operation.

The mean annual operating cost estimate is based on:

- Cleaning circuit operation of 13 hours per day (two shift operation), nominally five days per week

Table 4

ESTIMATED ORDER-OF-MAGNITUDE MEAN ANNUAL OPERATING COSTS(1)
WET HIGH GRADIENT MAGNETIC SEPARATION FINE COAL CLEANING CIRCUIT

Direct Operating Costs	Annual Requirements	Unit Costs	Annual Cost	Percent Of Total
Labor				
Supervision	5,824 hr	$9.87/hr	$ 57,500	0.9%
Operating	31,616 hr	8.17/hr	258,400	4.0%
Maintenance	9,152 hr	8.22/hr	75,200	1.2%
Subtotal, Labor	46,592 hr	$8.39/hr	$ 391,100	6.1%
Utilities				
Electricity	49.8x10^6kWh	$0.02/kWh	$ 996,000	15.6%
Water Treatment	1.52x10^9 gal	$0.15/1,000 gal	228,000	3.6%
Subtotal, Utilities			$1,224,000	19.2%
Materials and Supplies	Major Commodities			
Operating Supplies	Steel Balls, Filter Cloth		$ 71,000	1.1%
Chemicals	Flocculant, Sodium Silicate		236,000	3.7%
Maintenance Materials and Contracts			761,000	12.0%
Subtotal, Materials and Supplies			$1,068,000	16.8%
Subtotal, Direct Operating Costs			$2,683,100	42.1%
Indirect Operating Costs				
Depreciation — Straight Line 20 Year of Constructed Cost			$2,140,500	33.6%
Direct Payroll Overhead-35% of Direct Labor			136,900	2.1%
Administration and General Overhead-60% of Direct Labor			234,700	3.7%
Insurance and Local Taxes - 2.75% of Constructed Cost			1,177,300	18.5%
Subtotal, Indirect Operating Cost			$3,689,400	57.9%
Total Annual Operating Cost			$6,372,500	100.0%

Notes: (1) Actual annual operation is 3,250 hours.

- An annual operating time of 250 days
- Mid-1978 United Mine Workers of America labor rates
- Operation of the HGMS cleaning circuit at its hourly design coal feed rate
- For estimation of indirect operating costs, that the owners of the complete coal cleaning plant are a private corporation as defined by United States federal tax law

Estimated constructed capital cost, rather than total capital cost, was used to estimate both annual depreciation and insurance and local taxes. The reason for this is that the allowance for owners' costs portion of the total capital cost might be expensed, rather than capitalized, during cleaning plant engineering-construction. The allowance for owners' costs also includes land costs and possible other costs which are not depreciable under current tax law. If all or a portion of owners' costs are capitalized, the depreciation cost should be adjusted.

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TESTING OF COMMERCIAL COAL PREPARATION PLANTS WITH A MOBILE LABORATORY

William Higgins and Thomas Plouf
Joy Manufacturing Company
Denver, Colorado

No abstract or paper available.

CHEMICAL COMMINUTION--AN IMPROVED ROUTE TO CLEAN COAL

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ABSTRACT

Coal destined as fuel for electric power generation is often cleaned. A typical coal cleaning plant involves mechanical crushing followed by heavy medium separation facilities to remove pyritic sulfur and reduce ash content of the feed coal.

A new process to fracture coal by chemical comminution is presented which permits efficient removal of pyritic sulfur and ash-forming components. Raw coal is contacted with a low molecular-weight chemical such as ammonia vapor or liquid in a reactor system at moderate pressures and temperatures. The chemical disrupts the natural bonding forces acting across the internal boundaries of the coal structure where the pyritic sulfur and ash deposits are located. Because of the manner in which the pyrite is liberated, higher yields of clean coal for the same level of sulfur removal, or lower sulfur level at the same yield can be achieved using chemical fracturing as compared to mechanical crushing or grinding. Less fines are generated by chemically comminuting coal than by mechanical size reduction, thus permitting a significant increase in the usable coal fraction.

The process is in the development stage and indicates that production of a high-grade clean coal at considerable savings is possible.

Chemical comminution is a new technology for fracturing coal. Compared to mechanical grinding, in most cases it liberates more ash and pyritic sulfur from various grades of coal without creating substantial amounts of fines that complicate follow-on separation plants. Chemical comminution involves the exposure of coal to low-cost, recoverable chemical agents that disrupt the natural binding forces holding a lump of coal together. The concept, patented by the Syracuse Research Corporation, is currently at the bench-scale level of development, and a pilot plant is presently being considered.

This paper reviews the chemical comminution concept, describes probable pilot plant approaches, and provides results of two detailed economic studies. The economic studies compare chemical comminution to mechanical fracturing from the standpoints of equal coal feed and equal coal product yield. In each case chemical comminution provides favorable economic benefits. In Catalytic's view the values presented in terms of cost per million BTU's for the two comparisons represent the range of those likely to be realized.

FRAGMENTING COAL

Coal cleaning typically has two major steps: fragmenting followed by a separation process.

The fragmentation of coal releases impurities such as ash and pyrites. These impurities can be later separated from the coal, usually by methods that depend on density differences, such as heavy medium separation.

Traditionally, mechanical crushing has served as the fragmenting mechanism. Mechanical crushing usually takes the coal down to a 3/8-in. top size. Crushing fragments the coal and impurities in a random fashion, producing a wide spectrum of coal particle sizes. A significant amount of coal ground to 3/8 in. top size will result in fines below 100 mesh. Recovering these fines is frequently uneconomical, so they are often rejected with the tailings.

Finer mechanical grinding releases more coal impurities, but produces greater quantities of fines, complicating the separation process and raising cleaning costs. The added separation costs for handling fines limit the degree to which coal can be mechanically ground to liberate ash and sulfur.

Chemical comminution offers an attractive alternative to mechanical crushing for fragmenting coal. In this process the coal is exposed to low molecular weight chemicals, such as gaseous or liquid ammonia. The chemicals do not react with the coal, but disrupt the bonding forces holding coal particles together.

These natural boundaries among coal particles are often composed of impurities such as ash and pyrites. So the chemical mechanism, which is not completely understood, selectively attacks and releases the coal impurities.

The size distribution of the chemically comminuted coal depends on the natural fault planes within the coal, so the size distribution depends on coal petrology. Bituminous coals are most susceptible to chemical fracture, with susceptibility decreasing with increasing coal rank.

For the same amount of released impurities, chemically comminuted coal samples generally consist of larger coal particles compared to mechanically ground coal. Figure 1 compares particle size distributions of mechanically crushed and chemically comminuted Illinois No. 6 coal. Notice that for any given sieve designation, except for run of mine coal, chemical comminution produces a greater percentage of oversize particle coal. These larger particle sizes tend to reduce the cost of follow-on processing for separating ash and impurities, compared to mechanical crushing.

Chemical comminution not only produces larger particle sizes, but also tends to release greater amounts of impurities of comparable particle size distributions. Figure 2, for example, gives the results of float-sink tests on samples of coal fractured by chemical comminution and mechanical grinding. Taking, for example, a cumulative sulfur level of 1.4 percent, mechanically ground samples yield recovery levels of about 73 percent (above 100 mesh), while chemically comminuted samples yield over 95 percent recovery levels. So chemical comminution produces greater recovery yields for a given sulfur level, or cleaner coal for a given recovery level.

PROCESS DESCRIPTION

The chemical comminution process consists of five basic steps, as shown in Figure 3:

- o exposure of coal to chemical agent
- o washing coal to remove residual chemical
- o dewatering the resulting coal slurry
- o recovery of comminuting chemical
- o clarification and recycle of wash water

The wet, fragmented coal then would be sent to a separation process to remove released impurities such as ash and pyrites.

During the first step the degree of fragmentation depends primarily on chemical exposure time, temperature, and pressure.

The degree of fragmentation increases with increasing exposure time, leveling off after a period that depends on the nature of the coal. Probably the chemical agent diffuses through the larger coal boundaries first, but eventually reaches smaller connecting faults.

So penetration speeds depend on fault sizes. Maximum fragmentation for a low volatility bituminous coal, for example, occurs during about one and a half hours exposure to gaseous ammonia, as indicated in Figure 4.

Temperature and pressure also affect fragmentation because they affect such variables as diffusivity rates, surface tension, and similar properties that influence the chemical's rate of diffusion through the coal's capillary fault channels.

Chemical agents could be exposed to coal using either a batch or continuous approach. In a typical batch cycle, a vessel is charged with coal, sealed, and evacuated to remove air. The vessel is then pressurized in two steps with a chemical agent such as ammonia. The first step takes the vessel up to 60 psia by pressure equalization with a second vessel that has completed an exposure cycle. The second step raises the pressure to 120 psia, using an ammonia compresser or ammonia stored under regulated pressure. During exposure, the vessel temperature spontaneously rises to the range of 120° to 150° F due to the heat of solution as ammonia is absorbed in the coal moisture.

Following exposure of about 90 minutes, the vessel is depressurized first by equalization with a newly charged vessel and is then evacuated to 2 psia to minimize the retention of ammonia in the coal. Finally the vessel returns to ambient pressure, and the coal drops to a slurry mix tank.

A continuous reaction approach to chemical comminution is also possible and perhaps more economical. In this case the coal could be continuously charged and discharged through pressure-locking containers or devices. The use of a liquid chemical agent such as aqueous ammonia may simplify continuous charging, and provide some mechanical agitation to minimize exposure time.

The comminuting chemical does not react in any way with the coal; it's recovered by washing and stripping operations. Following exposure to the comminuting chemical, the coal would be mixed as a 35 percent slurry with water and fed to the mid-point of one or more washing towers. The coal drops through the lower tower section counter-current to hot water that extracts the remaining chemical.

The coal from the bottom of the washing towers would be dewatered by vibrating screens or centrifuges. Hot water with recovered chemical leaves the top of the tower and goes to a steam stripping operation to separate the chemical from the water.

ECONOMIC CONSIDERATIONS

Two detailed studies of the economics of chemical comminution versus mechanical fraturing are reported here. One, the more conservative study, compares mechanical and chemical coal cleaning plants having equal coal feeds that are designed for the requirements of an actual coal-fired utility station. This study leans heavily on the experience of Roberts & Schaefer Co. for estimates relating to modern mechanical crushing and separation plants. It assumes identical separation plants for the two plant types, just different fracture mechanisms. The specific gravities of the heavy medium solutions have been chosen to maximize premium coal produced for each case. Credit is given for excess premium yield above the amount required for the specific power station.

The second, more representative study, compares chemical and mechanical cleaning plants having equal coal product yields, of larger than 100 mesh material. In this case the coal feed rate of the chemical comminution plant is substantially less than that for the mechanical crushing. As stated earlier, for a given sulfur level output chemical comminution provides greater clean coal yields than mechanical fracture. Also in this study chemical comminution is given a capital credit for producing fewer fines.

Equal Coal Feed. Catalytic Inc. and Roberts & Schaefer Co. have made a rigorous, conservative economic comparison of two coal cleaning plants: one using chemical comminution and the other using mechanical crushing for coal fracture. The study was devised in cooperation with representatives of both the Electric Power Research Institute and the Tennessee Valley Authority. Both plants are rated at 1200 TPH coal feed, and conform to the specific requirements of the Homer City Station owned by the GPU and New York State Electric & Gas.

This station uses a 68:32 blend of Helvetia and Helen Upper and Lower Freeport coals. These coals are less amenable to chemical comminution for the release of ash and pyrites than a coal like Illinois No. 6, a factor that contributes to the conservative nature of this study. Laboratory work for the study was performed by Syracuse Research Corp.

The Homer City Station consists of three units. Two of these units must comply with the emissions requirement of 2 lbs of sulfur per million BTU's fired. The third unit must meet Pennsylvania New Source Performance Standards (NSPS) of 0.6 lbs of sulfur per million BTU's fired. For comparison purposes, Catalytic and Roberts & Schaefer prepared designs that would meet or exceed NSPS fuel requirements.

A key factor in this study is the credit for yields of NSPS fuel in excess of the basic quantity required for Homer City's Unit 3. The credit, suggested by EPRI, amounts to $0.65 per million BTU. This credit is sufficient to tip the economic balance in favor of chemical comminution despite higher capital investment and operating costs than mechanical crushing.

The two conceptual plant designs used in this study are identical except for the method of coal fracturing for liberation of pyrites and ash forming components. Roberts & Schaefer designed the mechanical crushing system, along with the separation system for both plants.

Catalytic designed the chemical comminution system for coal fracture. Both plants employ state-of-the-art technology for coal preparation.

The mechanical crushing plant has three parallel trains of 600 TPH feed capacity. It operates two shifts a day, resulting in an average daily output of 1200 TPH. The chemical comminution plant operates around-the-clock with two of three 600 TPH recovery trains on stream at all times. The idle train undergoes scheduled maintenance to increase plant reliability under conditions of continuous operation.

The washing sections for both plants are identical, consisting of two stage heavy medium separation including deep cleaning. The middling circuit gravity in the washing plant for the mechanically crushed coal is set at 2.03, which is relatively high and favors the mechanically crushed case.

Table 1 gives the estimated yields for both plants under the conditions set forth above. Premium yields for the chemical comminution plant are significantly higher in terms of both weight and BTU content. While the chemical comminution plant recovers 14.2 percent more BTU's as premium fuel, it loses 2.9 percent more BTU's as refuse.

Capital costs developed for the two plants, also given in Table 1, total $41.5 million for the mechanical crushing plant and

$62.6 million for the chemical comminution plant. Catalytic estimated the cost of the chemical comminution section to be $22 million; Table 1 shows, however, $20 million which accounts for a $2 million savings when the estimate for the chemical comminution and washing plants are made as one project rather than separate projects.

Annual operating costs given in Table 1 total $19.6 million for the mechanical crushing plant and $26.3 million for the chemical comminution plant, including the costs for deep cleaning using heavy medium separation. In terms of costs per million BTU's the figures are 9.3¢ and 12.9¢ respectively.

The average revenue required for production was developed for both mechanical crushing and chemical comminution using the Catalytic Clean Energy computer program. Plant life was assumed to be 20 years. Net results given in Table 1 indicate that the average revenue requirements are 4¢/MM BTU higher for the chemical comminution plant using regulated utility economics, and 4.8¢/MM BTU higher using a typical industrial discounted cash flow method.

The cost benefits favoring chemical comminution over mechanical crushing show up in the increased yield of premium low-sulfur product. Recalling the 65¢/MM BTU credit for premium fuel in excess of that required for Homer City's Unit 3, chemical comminution yields 59.3 - 45.1 or 14.2 percent more BTU's in the premium product. This gives chemical comminution a 9.2¢/MM BTU credit over mechanical crushing. Penalties noted in Table 1 for decreased BTU's recovered, increased ash disposal, and increased revenue requirements subtract 7.4¢/MM BTU from this figure. So the net economic benefit for chemical comminution is 1.8¢/MM BTU, or about $3.6 million a year under utility economics.

Equal Product Yield. Another way to look at the economics of chemical comminution versus mechanical crushing is to compare plants having equal product yield rather than equal coal feed. Chemical comminution yields greater recovery values for the same sulfur content, requiring less coal feed capacity than mechanical crushing. This leads to decreased capital and operating costs for chemical comminution compared to the equal coal feed case discussed earlier.

This equal product yield study conducted by Catalytic assumes that the raw input coal (Illinois No. 6) is sized less than 1½ inches, and contains 2.1 percent sulfur. 12.5 percent ash; and 12,500 BTU/lb. For purposes of calculating the unequal input coal costs for the two plants, the coal's value is set at $1/MM BTU.

Product is considered to be only the yield over 100 mesh. The washing plant receives coal fractured by chemical comminution or mechanical crushing to 3/8 in. top size. The study assumes that the washing plant operates 330 days/year.

For a cumulative sulfur value of 1.4 percent in the output of the washing plant, Figure 2 gives recovery yields over 100 mesh of 73 and 95 percent by weight for mechanical crushing and chemical comminution respectively. As indicated in Table 2, these recovery values lead to coal feed rates of 12,000 TPD for mechanical crushing and 9,000 TPD for chemical comminution to produce equal 8,000 TPD coal product yields.

Using Roberts & Schaefer figures, Catalytic estimates the total capital investment for a 12,000 TPD mechanical crushing and washing plant would come to $36.5 million, as shown in Table 2. These figures include land, interest during construction, startup, working capital requirements, and contingency capital.

Capital investment figured similarly for the 9,000 TPD chemical comminution plant would total $42.6 million, but this plant is given a $5 million credit that takes the total down to $37.6 million. The credit is for 5.5 percent fewer 28 x 100 mesh fines produced by chemical comminution, with an estimated worth of $11,000 in capital cost savings per daily ton of reduced fines production.

Total annual operating costs for the mechanical crushed and chemical comminuted cases come to $109.5 million and $82.7 million respectively. The cost of coal dwarfs other operating costs for chemicals, labor, maintenance and physical separation. Since the chemical comminution plant uses 25 percent less coal than the mechanical fracturing plant for the same product yield, operating costs for chemical comminution are substantially lower.

Mechanical crushing generates significantly more refuse coal than chemical comminution. The resale value of this refuse could represent a credit to operational costs rather than a debit for disposal. Calculating operational costs with this credit included brings the total for mechanical crushing down to $95.8 million, shown in Table 2 in parentheses. The corresponding total for the chemical comminution case is $80.8 million, representing only a small change since it generates relatively little refuse.

Table 2 also gives average revenue requirements for the chemical comminution and mechanical crushing cases. Using regulated utility economics, and including the resale value of refuse, chemical comminution costs 17¢/MM BTU's less than the mechanical crushing plant. This calculation assumes 12 percent return on utility investment, 10 percent interest with 65 percent debt financing, and income tax at a 50 percent rate.

Under commercial economics, based upon 15 percent discounted cash flow and 65 percent debt financing, chemical comminution costs are estimated to be 16¢/MM BTU less than mechanical crushing.

SUMMARY

Chemical comminution appears to cost less than mechanical fracture in both the equal coal feed and equal coal product yield cases. In Catalytic's view these two comparisons probably represent the range of conservative and liberal viewpoints. Most likely the actual economic benefit of coal comminution lies somewhere between the 1.8¢ and 17¢/MM BTU values presented here.

To sum up, chemical comminution, in combination with conventional coal separation processes, offers a promising alternative to mechanical crushing for coal cleaning. Its special economic value lies in its ability to improve the yield of cleaned coal product without simultaneously producing a greater volume of fines.

This new technology warrants further development as a cost-effective way to meet increasingly stringent pollution standards using cheaper, lower grade coals. Coal cleaning alone may not meet future New Source Performance Standards as it appears that the new NSPS levels will be based on a percentage sulfur reduction between mine and stack mouth. In the case of many coals, the combination of coal cleaning and flue gas desulfurization may well be the most economical approach. In some cases where coal sulfur contents are high coal cleaning may be mandatory due to scrubber efficiency limits. The shorter the averaging period for sulfur measurement, the more difficult the job becomes.

Catalytic is presently seeking a pilot plant host site, preferably in a utility industry coal cleaning test facility. It is felt that a batch reaction, gas phase comminution plant in the size range of 2 tons per hour can provide meaningful engineering and optimization data. Such a plant is currently under consideration.

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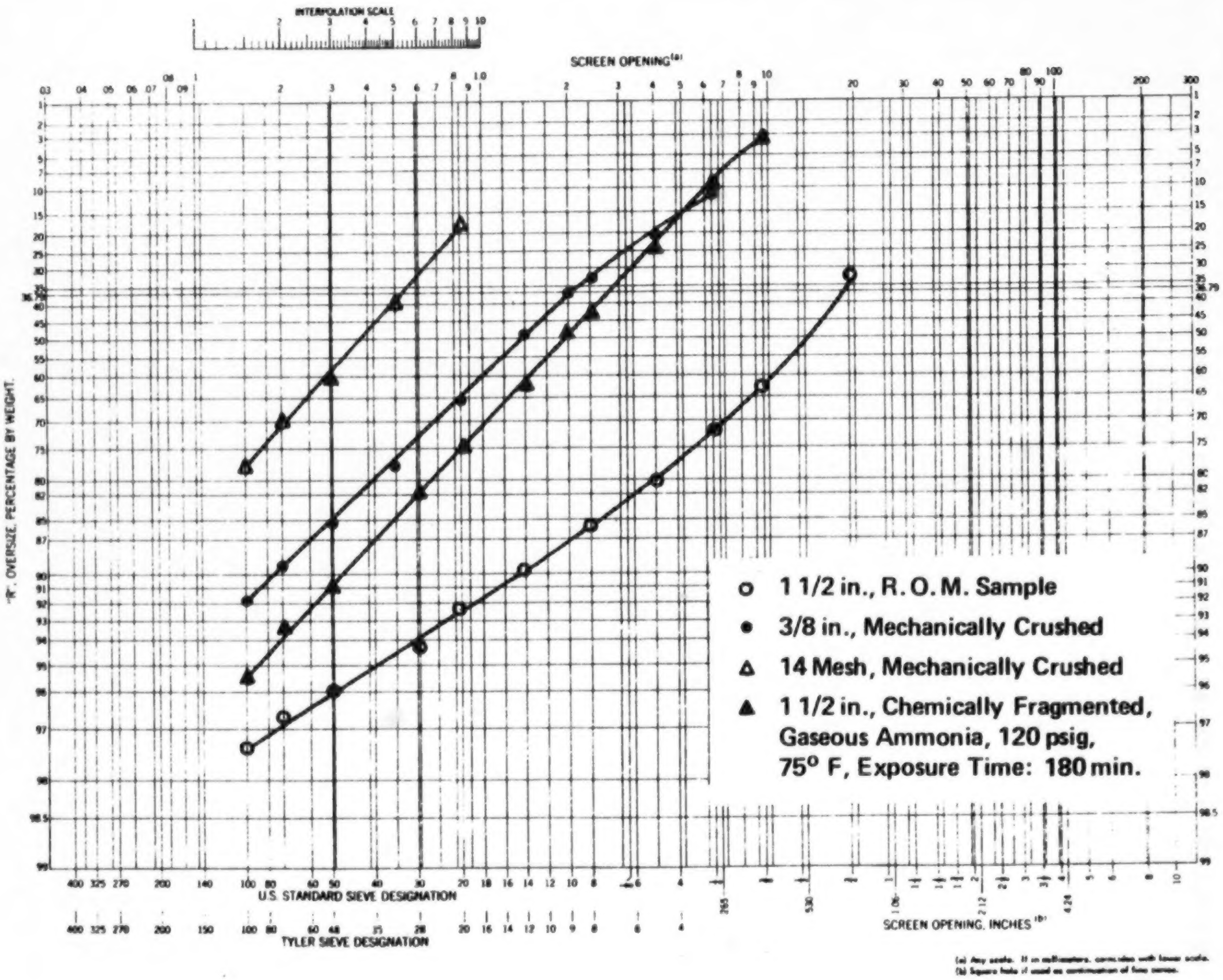

Figure 1. Coal particles fragmented by chemical comminution tend to be larger than those mechanically crushed.

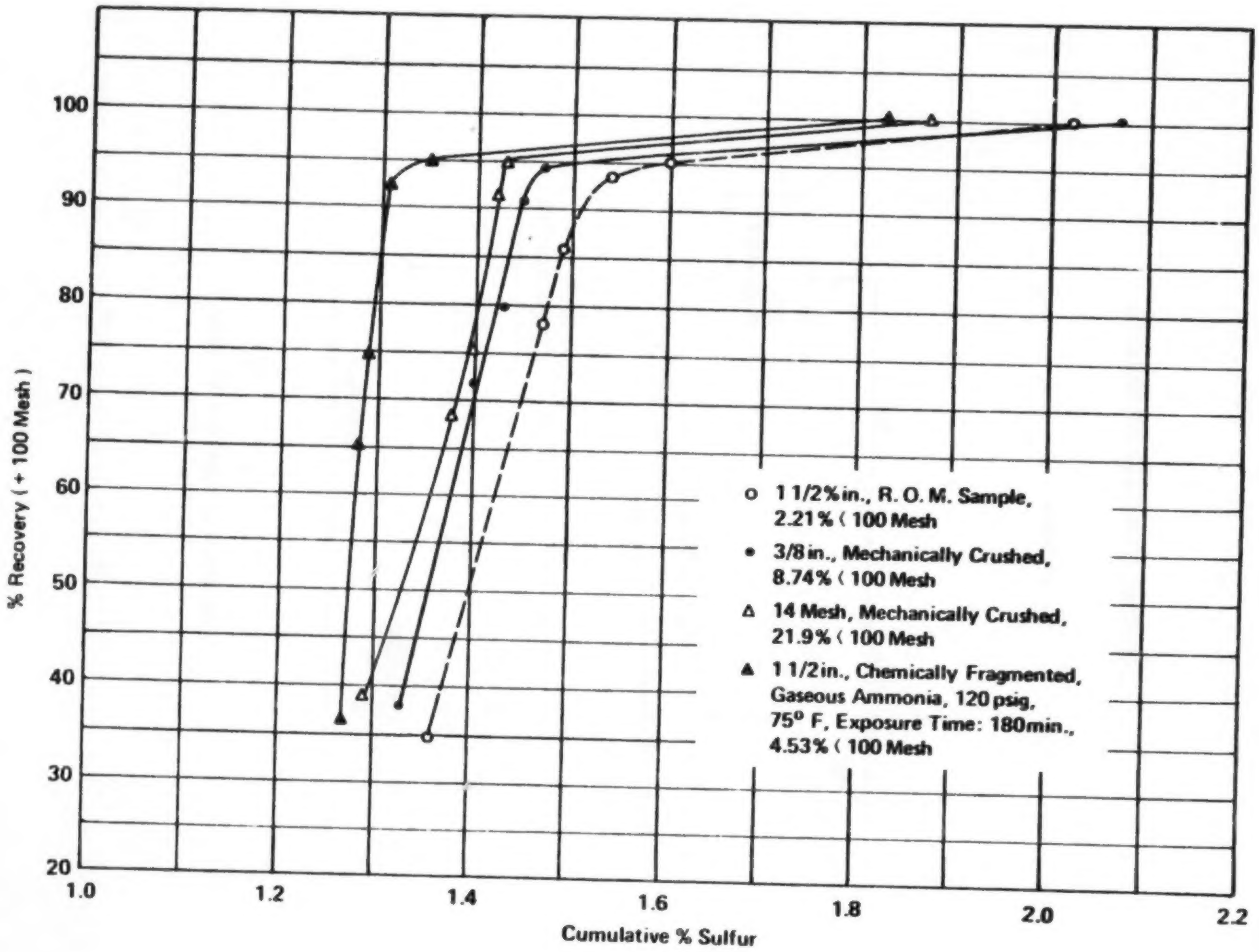

Figure 2. Chemical comminution produces greater coal recovery yields over 100 mesh for a given sulfur level than mechanical crushing.

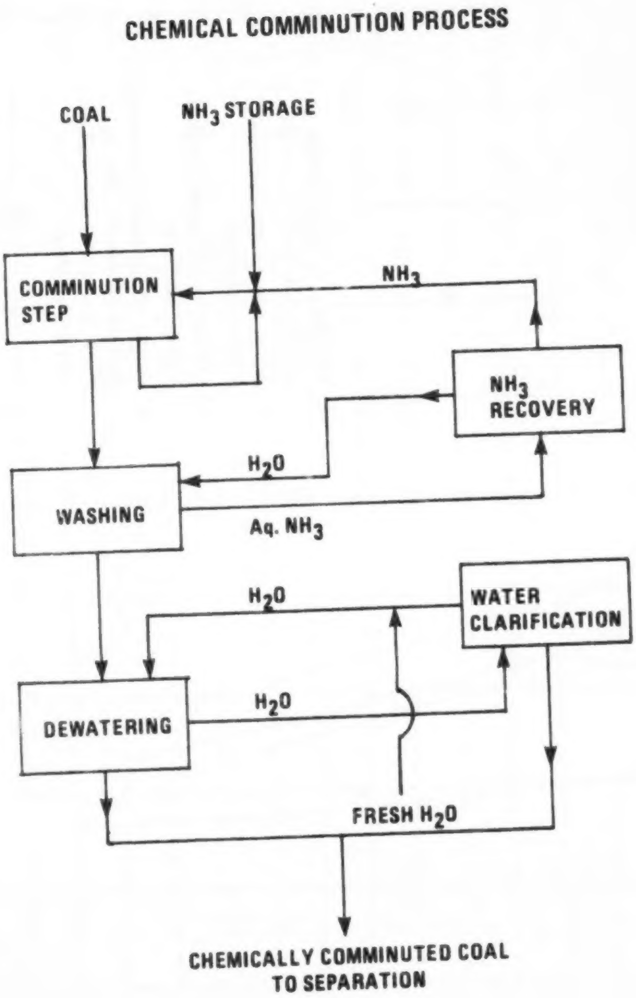
CHEMICAL COMMINUTION PROCESS
COAL
NH_3 STORAGE
COMMINUTION STEP
NH_3
NH_3 RECOVERY
H_2O
WASHING
Aq. NH_3
H_2O
WATER CLARIFICATION
DEWATERING
H_2O
FRESH H_2O
CHEMICALLY COMMINUTED COAL TO SEPARATION

Figure 3. The five basic processing steps for chemical comminution.

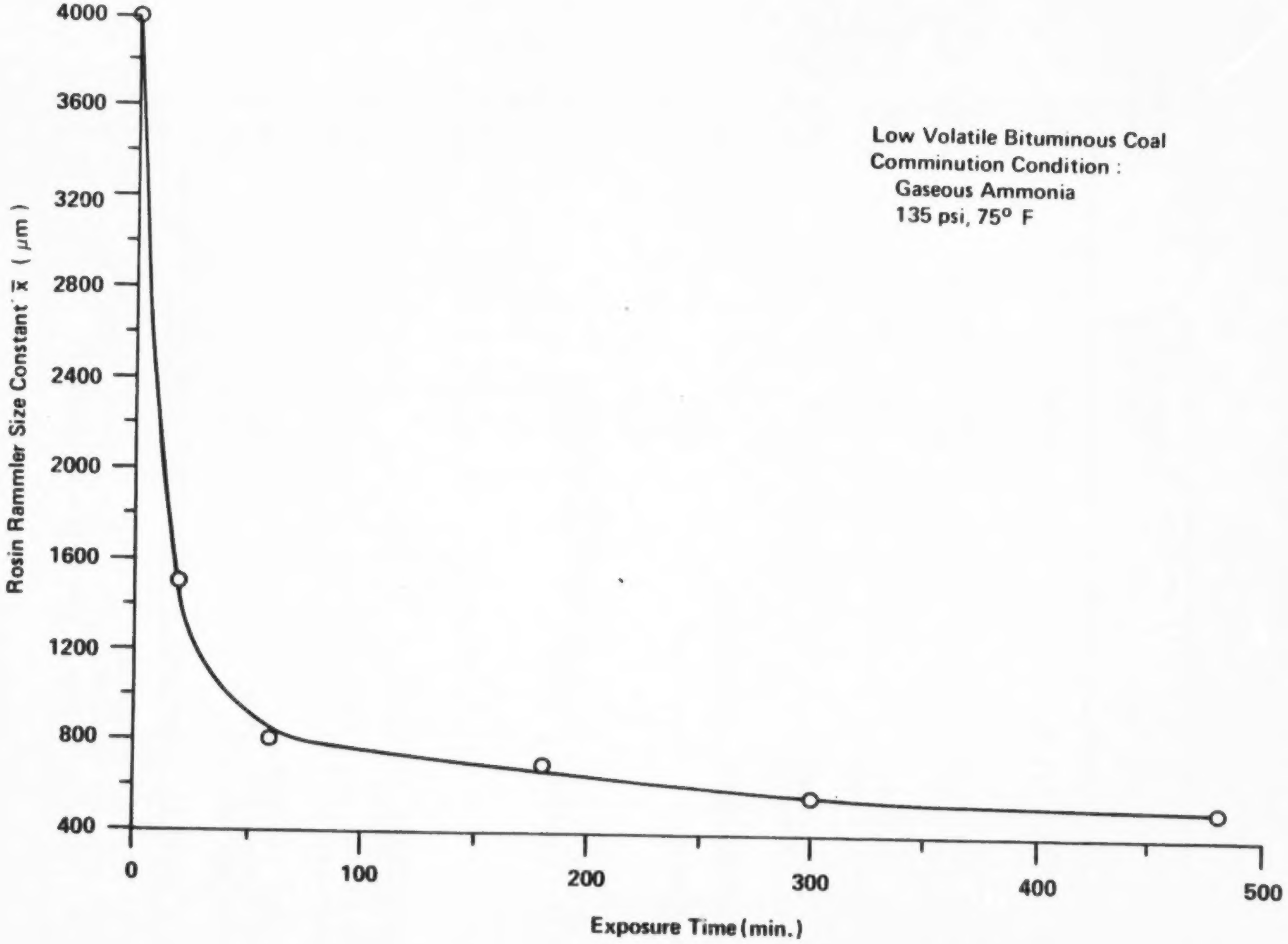

Figure 4. In chemical comminution processing nearly all coal fragmenting takes place during the first 90 minutes exposure to gaseous ammonia.

TABLE 1: ECONOMIC COMPARISON -- EQUAL COAL FEED

	Mechanical Crushing		Chemical Comminution	
Coal Feed, TPH	1200		1200	
Yields				
Premium Yield				
TPH (% of feed)	412	(34.3)	552	(46.0)
BTU,(% of feed)	45.1		59.3	
Middlings yield				
TPH (% of feed)	608	(50.7)	403	(33.6)
BTU (% of feed)	51.7		34.6	
Refuse yield				
TPH (% of feed)	180	(15.0)	245	(20.4)
BTU (% of feed)	3.2		6.1	
Capital Investment, $ Millions				
Fracture	2.		20.	
Washing Plant	33.		33.	
Other	6.5		9.6	
Total	41.5		62.6	
Annual Operating Cost, $ Millions (¢/MM BTU)				
Materials (excluding coal)	12.77	(6.1)	17.91	(8.8)
Labor	1.29	(0.6)	1.84	(0.8)
Utilities	2.5	(1.2)	1.97	(1.0)
Fixed	3.04	(1.4)	4.60	(2.3)
Total	19.6	(9.3)	26.33	(12.9)
Average revenue required				
Utility economics				
$ Millions per year	22.7		30.9	
Cents per MM BTU	11		15	
Commercial economics				
$ Millions per year	24.1		33.1	
Cents per MM BTU	11.4		16.2	
Economic benefit, chemical comminution, ¢/MM BTU				
Excess premium yield			+ 9.2	
Decreased BTU's recovered			- 2.9	
Increased ash for disposal			- 0.5	
Increased production costs (utility economics)			- 4.0	
Net economic benefit			+ 1.8	

TABLE 2: ECONOMIC COMPARISON -- EQUAL PRODUCT YIELD

	Mechanical Crushing	Chemical Comminuted
Feed Coal, TPD	12,000	9,000
Yield		
Product (+100 Mesh)		
TPD	8,000	8,000
Ash, wt.%	5.2	8.8
BTU value, per lb	13,500	13,000
Fines, TPD	1,000	400
Rejects, TPD	3,000	600
Capital Investment, $ millions		
Chemical Treatment		11.0
Washing Plant	20.0	16.0
Credit less Fines		(5.0)
Contingency	4.0	5.0
Plant Facility Investment	24.0	27.0
Total Capital Investment	36.5	37.6
Annual Operating Cost, $ millions		
Coal	99.0	72.8
Production Costs	6.9	7.0
Refuse Disposal (Resale)	1.3 (12.4)	0.3 (1.6)
Fixed Costs	2.3	2.6
Total Operating Cost	109.5 (95.8)	82.7 (80.8)
Average Revenue Required		
Utility Economics		
$ millions per year	112.8 (99.1)	85.9 (84.0)
Cents per MM BTU	1.58(1.39)	1.25(1.22)
Commercial Economics		
$ millions per year	115.4 (101.7)	88.1 (86.2)
Cents per MM BTU	1.60(1.41)	1.27(1.25)

CONVERSION TABLE

English to International System of Units (SI)

BTU x 1.0550559 = kilojoule

BTU/lb x 2.32600 = joule/gram

degree Fahrenheit, ^{o}F: (t_F + 459.67)/1.8 = degree kelvin, ^{o}K

inch x .0254 = meter

pound x .45359237 = kilogram

psi x 6.8947573 = kilopascal

ton x 907.18474 = kilogram

COAL CLEANING BY THE OTISCA PROCESS

C. D. Smith
Otisca Industries, Ltd.
P. O. Box 186
LaFayette, New York 13084

ABSTRACT

A brief overview of the Otisca Process will survey bench scale and continuous pilot plant work to date, current projects, economics, and environmental impact.

Otisca Industries, Ltd. was founded in August, 1972 by Dr. D. V. Keller, Jr., a chemist and C. D. Smith, a mechanical engineer. Through a private venture capital stock issue, approximately $250,000 was raised to support efforts focused on the commercialization of techniques that had demonstrated bench scale results that projected potential commercial efficiency and economics in the areas of fossil-fuel extraction and upgrading.

Six years of development and growth resulted in a company that, in 1978, organized its approximately 30 employees into four groups: basic and applied laboratory, engineering, construction, and operation.

Techniques that have been or are being studied are chemical comminution, the Otisca media or heavy liquid coal separation technique, tar sand-hydrocarbon solvent extraction, a coal beneficiation process called the T-Process, and a coal beneficiation process called the B-Process. This paper will focus on the development to-date of the Otisca heavy liquid or media coal beneficiation process.

The Otisca media coal beneficiation process uses an organic heavy liquid - trichlorofluoromethane (CCl_3F) rather than water and magnetite. Gravimetric separation of product coal from reject material takes place in a bath of media at ambient conditions. Table 1 compares some of the properties of Otisca media with those of magnetite and water.

Table 1

	Otisca Media	Mag. & H_2O
1. Boiling Point (°F)	75	212
2. Latent Heat (Vap) (BTU/lb)	80	1000
3. Surface Tension Dynes/Centimeters	20	80
4. Viscosity (20°C - Centipoise)	0.4	14

The toxicity of the Otisca media is very low and is rated in category 5A, by Underwriters Laboratories. It is non-flammable, non-explosive and virtually odorless. It's chemical stability is very high and in a coal processing situation, the fact that it is a non-polar solvent, has the effect of reducing corrosion potential virtually to zero especially as compared to water with pH difficulties that develop when it is associated with the coal and its various sulfur forms.

Another property which supports media's unique ability to separate ultrafine particles is that with a volume percent solids in a media slurry of 11.4%, yield stress is 15×10^{-4} dynes per square centimeter as compared to a magnetite water slurry with a 37 volume percent solids, yield stress would be

26 dynes per square centimeter. (Keller, 1978)

Typically, raw coal arrives at a preparation plant with 2 to 5% surface moisture, which is usually the result of dust control techniques and exposure to the elements. Depending on the site conditions and raw coal handling techniques, opportunities generally exist for clays to be dispersed in this water film. Otisca, where appropriate, can add compounds to the media which enhance a transfer of raw coal surface moisture to the refuse, in a low shear mixer, which we call a conditioner. The conditioner's basic duty is to prepare the coal for separation in the separator by adjusting its temperature, and by removing slimes from the surface of the product coal and transferring them to the refuse material. This phenomenon apparently is the result of the hydrophobic characteristics of the media, the hydrophobic surface of the product coal and by the hydrophilic characteristics of the majority of the refuse material.

In 1972, Otisca started bench scale and batch pilot plant activity in a small structure in LaFayette, New York. A 600 pound batch pilot plant was constructed and operation of this plant commenced in 1973. Table 2 demonstrates the effects of bench scale activity and batch pilot plant work to a run of mine analysis.

Table 2

UPPER FREEPORT (PENNA.)

	Run of Mine	Bench Scale	Pilot Plant
Volatile Matter	26.09	36.75	36.62
Fixed Carbon	37.34	55.36	56.08
Ash	36.57	7.89	7.30
% Reduction	-	85.9	87.0
Total Sulfur	1.55	0.98	0.88
% Reduction	-	58.6	63
Pyritic Sulfur	1.22	0.53	0.56
% Reduction	-	71.4	70
BTU/lb	9,128	13,911	14,009
Weight Yield	-	52.8	54.8
BTU Yield	-	80.5	84.1
Specific Gravity	-	1.50	1.50
Moisture	6.5	-	2.07
MASS		1 lb.	600 lb. Batch

It is important to note that in scale up from bench scale to batch pilot plant, ash and sulfur reduction values were the same or better due to the reduction of edge effects. Through the operation of this batch plant, it was also observed that the Otisca technique was capable of reducing surface moisture, as evidenced by total moisture in the run of mine of 6.5% being reduced to pilot plant product coal of 2.07%.

Studies at this facility in LaFayette, New York from 1972 until 1975 focused on approximately 30 United States' bituminous coals. The batch plant was decommissioned in 1976.

As a result of these laboratory and batch pilot plant studies, Island Creek Coal Company supported the construction and operation of a continuous pilot plant sited at their North Branch Mine near Bayard, West Virginia. The continuous plant constructed under a very tight budget was designed to treat a 1/4 x 0 slack coal. It operated at the mine site from approximately June, 1976 until January, 1977. Representative raw coal and product coal analyses of the plant operation are shown in Table 3. During the operation of the plant, substantial physical changes were made to enhance the ability of the installed hardware to separate coal, recover the media and stably and continuously convey the solids. (Keller, Smith & Burch, 1977)

Figure 1 - Otisca Coal Beneficiation Plant - provides a block diagram which provides an overview of the major unit operations involved in the process. Raw coal, comminuted as required to meet a balance between maximum top size and product coal specifications, is introduced to a conditioner where its temperature is neutralized relative to the bath operating temperature, and, where appropriate, surface moisture is transferred to refuse. The conditioned raw coal is transferred to a separating bath where conveyors skim the surface and

Table 3

Representative Analyses Of The North Branch Upper Freeport Raw Slack Coal and Product Coal Separated From This

		Raw Coal	Product Coal
Volatile Matter	%	17.70	19.12
Fixed Carbon	%	60.65	71.22
Ash	%	21.65	9.66
lbs/MM BTU		18.33	6.93
Total Sulfur	%	2.63	1.53
lbs/MM BTU		2.23	1.10
Pyritic Sulfur	%	1.54	0.62
lbs/MM BTU		1.30	0.44
Organic Sulfur	%	1.05	0.87
lbs/MM BTU		0.89	0.62
BTU/lb		11,812	13,933
BTU/lb (MAF)		15,076	15,423
Weight Yield	%	-	74.9
BTU Yield	%	-	88.3
Specific Gravity		-	1.50

FIGURE 1

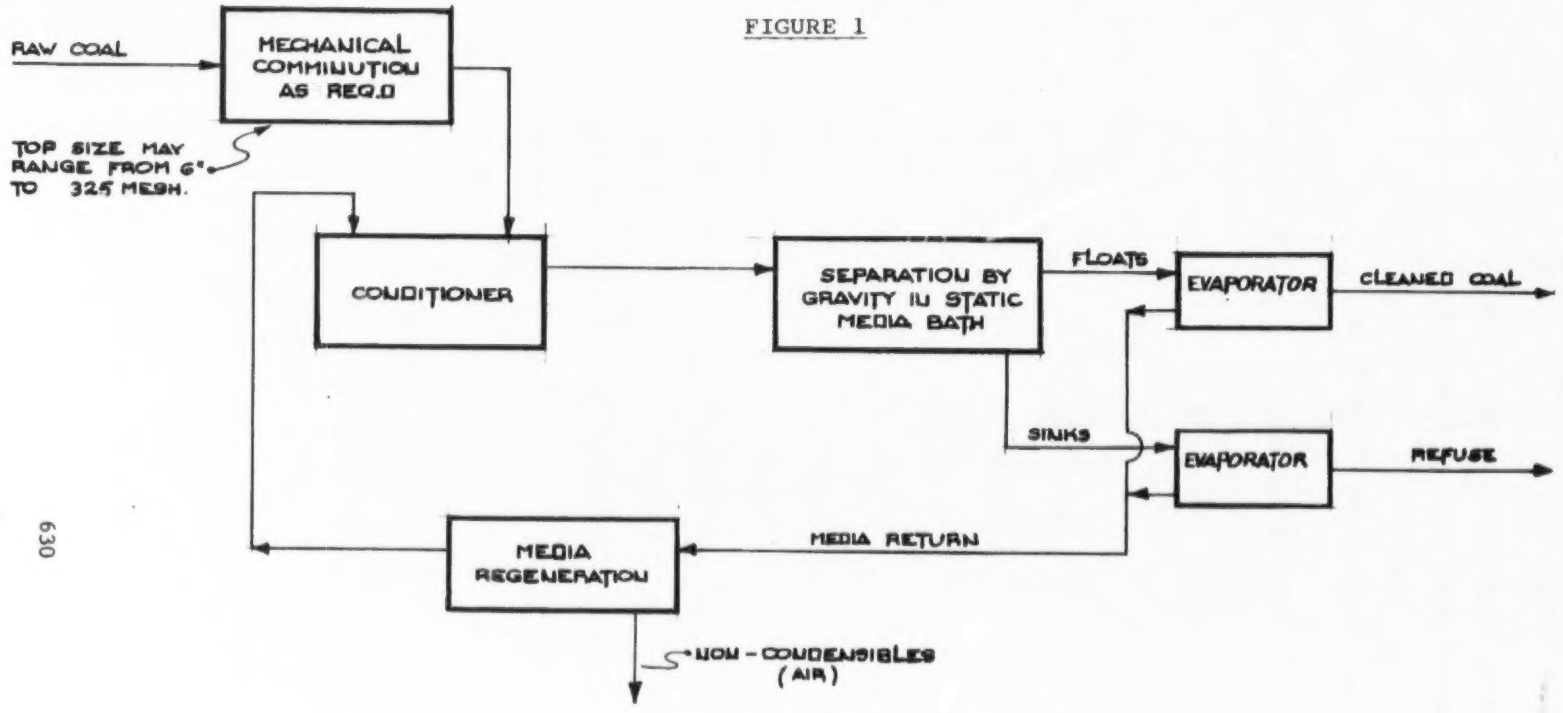
RAW COAL
MECHANICAL COMMINUTION AS REQ.D
TOP SIZE MAY RANGE FROM 6" TO 325 MESH.
CONDITIONER
SEPARATION BY GRAVITY IN STATIC MEDIA BATH
FLOATS
EVAPORATOR
CLEANED COAL
SINKS
EVAPORATOR
REFUSE
MEDIA RETURN
MEDIA REGENERATION
NON - CONDENSIBLES (AIR)

FIGURE #1 OTISCA COAL BENEFICIATION PLANT

PATENT PENDING JULY 1975
C.D.S.

OTISCA INDUSTRIES LIMITED
P.O. BOX 211, LAFAYETTE, NEW YORK 13084

23rd July '76

remove float for drip drying and convey them to a product coal evaporator. Sinks or rejects are conveyed from the bottom of the bath to the rejects evaporators. The evaporators are indirect fired, conductive evaporators, wherein the product coal or rejects are heated to approximately 100°F, which results in complete evaporation of the separating liquid.

Vapors are collected from the evaporators, carried in ducts to recovery equipment, which generally consists of compressor-condensing stages followed by polishing of non-condensibles by either carbon adsorption or liquid absorption.

Product coal from the plant is discharged from a rotary valve, virtually free of surface moisture and it can be conveyed and stored in conventional equipment. Rejects are discharged through a rotary valve to conventional material handling equipment, in a physical condition that is not difficult to handle. Typically, the ease in handling the refuse stems primarily from the fact that it contains enough moisture not to be dusty, but not so much moisture that it is runny or extremely adhesive.

In 1977, the continuous pilot plant equipment at Bayard was relocated to Florence, Pa. with the objective of continued operation to demonstrate at relatively large scale, the ability of the process to separate raw coal, and to provide bulk samples for testing relative to the commercial use of the product coal. An additional objective was to continue process hardware development through the installation and operation of modified or completely different unit operations. Demonstration and unit test work continue at Florence.

In 1977, demonstration work at the Florence Development Center led to the signing of a contract with American Electric Power for Otisca to construct and operate a 125 TPH Otisca Demonstration Plant at American Electric Power's Muskingum Mine near Beverly, Ohio. The facility, which is presently under construction, is essentially a complete coal preparation facility in that it has its own site services, raw coal storage, raw coal recovery, crushing station, crushed coal storage, the Otisca separation facility, refuse storage and handling bin and a product coal stacking conveyor. The total budget for the construction, start-up and operation of the plant is 6.7 million dollars.

Plant start-up is projected for the third quarter of 1979, with Otisca responsible for the design, construction and operation of the plant. It is important to note that the 6.7 million dollar budget covers the installation and operating cost of a significant amount of instrumentation and/or equipment that would not be found in a commercial cost beneficiation plant, whose objectives did not include the monitoring and generating of a significant amount of detailed operating data.

Table 4 provides an overview of separating characteristics and by-product generation of untreated coal. Conventional hydroprocess (water-magnetite) and coal cleaned by the Otisca media process. The comparison represented in the table relates to the electricity consumed annually by an all electric house in Ohio (25,000 kilowatt hours per year). Boiler fuel consumption in the comparison is based on an overall combustion generation and distribution efficiency of 35%. Values for sludge from scrubbers assume the generation of 10 pounds of sludge per 1 pound of sulfur in the input coal.

Table 4

	Untreated Coal	Existing Hydro-Process	Coal Cleaned By Otisca Process
% Ash	24.8	18.0	11.5
% Sulfur	6.2	5.8	4.2
BTU/lb	10,700	11,500	12,700
lbs Coal/Year to Produce 25,000 KWH	2.3×10^4	2.12×10^4	1.92×10^4
lbs Ash/Year	5,704	3,819	2,208
lbs Sulfur/Year	1,426	2,131	806
lbs Sludge/Year During Clean-Up of Sulfur	14,260	12,310	8,060
Emissions of CFM lbs/Year	0	0	0.1 - 0.5

There are 14,260 pounds of sludge generated per year from stack gas scrubbing of untreated coal; 8,060 pounds of sludge are generated per year for coal cleaned by the Otisca Process, giving a net reduction of 6,200 pounds of sludge per year, which trade off against an emission of trichlorofluoromethane of 0.1 to 0.5 pounds per year. (Otisca Industries, Ltd., 1978)

Comparative economics for a 400 TPH with a 1/2" x 0 feed are listed below. The comparison intent is to fairly relate the relative capital and operating cost of a conventional preparation plant assuming that that plant is equipped with separating techniques capable of cleaning to ultrafine sizes,, and that the product coal will be mechanically or thermally dewatered to an equivalent level with the Otisca Process. The comparison assumes a relatively typical case study for a coal preparation plant involving annual operation of approximately 3,200 hours per year.

Table 5

Comparative Economics

400 Tons/Hour

1/2" x 0 Feed

		Conventional Preparation	Otisca (Media)
First Cost:			
Unit Cost	$/Ton-Hr.	25,000	15,000
Total Cost		10,000,000	6,000,000
Direct Operating Cost:			
(Labor, Power, Fuel, Mat'l, Maint.) $/Raw Ton		2.00	1.45
Total Cost:			
(At 15% Return on Investment $/Raw Ton)		5.47	3.65

The word Otisca is an Onondaga Indian word meaning waters much gone away or water much dried away. It is projected that the demonstrated economics and efficiencies of the Otisca Process which result in higher BTU yield per ton of raw coal at projected lower operating cost will continue to motivate additional development work and the near-term commercial acceptance of the process as a practical and useful technique to upgrade raw coal for downstream use for power generation, coke manufacture, solvent extraction, gasification and liquefaction processes.

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